Docket No.: A.20-07-002

Exhibit No.:

Date: September 24, 2020

Witness: Brian Dickman

PREPARED DIRECT TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE JOINT COMMUNITY CHOICE AGGREGATORS
IN PACIFIC GAS AND ELECTRIC COMPANY'S
2021 ERRA FORECAST PROCEEDING

PUBLIC

Table of Contents

TABLE OF ACRONYMS

Acronym	Description
3CE	Central Coast Community Energy
A.	Application
AFR	Application for Rehearing
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator
CPE	Central Procurement Entity
CPUC	California Public Utilities Commission
CS-GT	Community Solar Green Tariff
CTC	Competition Transition Charge
D.	Decision
DAC-GT	Disadvantaged Community Green Tariff
EBCE	East Bay Community Energy
ECR	Enhanced Community Renewables
ERRA	Energy Resource Recovery Account
ESA	Energy Supply Administration
GHG	Greenhouse Gas
GRC	General Rate Case
GTSR	Green Tariff Shared Renewables
GWh	gigawatt-hour
IOU	Investor-Owned Utility
JCCAs	Joint Community Choice Aggregators
Joint CCAs	Joint Community Choice Aggregators
kWh	kilowatt-hour
LSE	Load Serving Entity
MCE	Marin Clean Energy
MPB	Market Price Benchmark
MWh	megawatt-hour
NBC	Non-Bypassable Charges
NSGBA	New System Generation Balancing Account
PABA	Portfolio Allocation Balancing Account
PCE	Peninsula Clean Energy Authority
Pioneer	Pioneer Community Energy
PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreements
PPP	Public Purpose Program
PUBA	PCIA Under-collection Balancing Account
RA	Resource Adequacy
REC	Renewable Energy Certificate
RPS	Renewable Portfolio Standard
SCE	Southern California Edison

SJCE	San José Clean Energy
SVCE	Silicon Valley Clean Energy Authority
SCP	Sonoma Clean Power
UOG	Utility-Owned Generation
WEMA	Wildfire Expense Memorandum

I. INTRODUCTION AND SUMMARY OF TESTIMONY

Central Coast Community Energy ("**3CE**"),[1] CleanPowerSF,[2] East Bay Community Energy ("**EBCE**"),[3] Marin Clean Energy ("**MCE**"),[4] Peninsula Clean Energy Authority ("**PCE**"),[5] Pioneer Community Energy ("**Pioneer**"),[6] San José Clean Energy ("**SJCE**"),[7] Silicon Valley Clean Energy Authority ("**SVCE**"),[8] Sonoma Clean Power ("**SCP**"),[9] and Valley Clean Energy Alliance ("**VCE**")[10] (collectively "the **Joint CCAs**") present this direct testimony in the *Application of Pacific Gas and Electric Company ("**PG&E**") for Adoption of Electric Revenue Requirements and Rates Associated with its 2021 Energy Resource Recovery Account ("**ERRA**") and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* ("**Application**"). This testimony has been prepared on behalf of the Joint

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1 3CE, formerly known as Monterey Bay Community Power Authority, is the community choice aggregator ("CCA") for Monterey, San Benito and Santa Cruz Counties and parts of San Luis Obispo County. Service will be initiated to some cities in and the county of Santa Barbara in 2021.

2 CleanPowerSF is the CCA for the City and County of San Francisco operated by the San Francisco Public Utilities Commission.

3 EBCE is the CCA for Alameda County.

4 MCE is the CCA for Marin County, unincorporated Napa County, unincorporated Contra Costa County, unincorporated Solano County, and the Cities and Towns of American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek.

5 PCE is the CCA for San Mateo County.

6 Pioneer is the CCA for Placer County.

7 SJCE is the CCA for the City of San José.

8 SVCE is the CCA for unincorporated Santa Clara County, and the Cities and Towns of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Milpitas, Monte Sereno, Morgan Hill, Mountain View, Saratoga and Sunnyvale.

9 SCP is the CCA for the Cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits and the Town of Windsor, and the Counties of Sonoma and Mendocino.

10 VCE is the CCA for the cities of Davis and Woodland and the unincorporated areas of Yolo County.

CCAs by Brian Dickman, Executive Consultant, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment A.

The Joint CCAs have a particular interest in the Power Charge Indifference Adjustment ("**PCIA**") and the Portfolio Allocation Balancing Account ("**PABA**"), both of which are charged to the Joint CCAs' customers through the PCIA rates for which PG&E seeks approval in this proceeding. This testimony focuses on the following issues in Commissioner Guzman Aceves' September 10, 2020 Scoping Ruling:[11]

a. Whether PG&E's requested 2021 ERRA forecast revenue requirement, ongoing Competition Transmission Charge (CTC), Power Charge Indifference Amount (PCIA), Cost Allocation Mechanism (CAM), and Tree Mortality Non-Bypassable Charge are reasonable and should be adopted;

b. Whether the Commission should adopt PG&E's Greenhouse Gas (GHG) related forecast for 2021 of GHG allowance revenues and returns, including Administrative and Outreach Expenses, GHG administrative and outreach set-aside true-up, Customer Generation Program Expenses, Net GHG revenue return, and per household Semi-Annual Residential California Climate Credit;

c. Whether all calculations and entries, including but not limited to ERRA, Ongoing CTC, PCIA, CAM, procurement costs, and GHG related items, including the funding of GHG clean energy programs such as the Solar on Multifamily Affordable Housing program, are in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes;

d. Whether PG&E's or any other party's rate proposals associated with PG&E's proposed total electric procurement revenue requirements for 2021 should be approved;

e. Whether the Commission should approve PG&E's proposal to credit the 2019 ERRA overcollection to vintage 2019 and vintage 2020 customers; and

f. Whether the Commission should approve PG&E's proposal to transfer certain

[11] A.20-07-002, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 2-3 (Sep. 10, 2020) ("2020 Scoping Ruling"). Scoping item b) Whether the Commission should adopt PG&E's 2021 electric sales forecast is implicated by forthcoming information and updates due to be provided by PG&E after the filing of this testimony. The procedural schedule calls for PG&E to file supplemental testimony concerning the 2021 load forecast on October 26, 2020. The Joint CCAs will address that issue, as necessary, in our response to the November Update.

> year-end ERRA balances, excluding deferred revenue resulting from capped vintage PCIA rates, through a balancing account transfer to the latest vintage in Portfolio Allocation Balancing Account in the current proceeding and on a going-forward basis.

PG&E's proposal will unreasonably increase the PCIA for all customers, including PG&E's bundled customers and the Joint CCAs' unbundled customers. PG&E's proposed system average PCIA rates by vintage are summarized in Table 1 below along with a comparison to the 2020 PCIA rates. PG&E's request in its Application, updated in its Supplemental Testimony, results in a *single-year* PCIA rate increase of between 16% and 21% for vintages 2009 through 2018. The 2019 and 2020 vintage rates decrease due to crediting the PABA for the respective share of PG&E's ERRA overcollection balance.

Table 1: PG&E Proposed PCIA Rates by Vintage

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2020 Capped	$0.0243	$0.0273	$0.0297	$0.0296	$0.0316	$0.0321	$0.0319	$0.0318	$0.0317	$0.0317	$0.0338	$0.0406	
2020 Uncapped	$0.0326	$0.0394	$0.0414	$0.0431	$0.0437	$0.0438	$0.0439	$0.0434	$0.0427	$0.0420	$0.0406	$0.0406	
2021 Capped	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0388	$0.0456	
2021 Uncapped	$0.0357	$0.0418	$0.0435	$0.0452	$0.0457	$0.0458	$0.0461	$0.0460	$0.0469	$0.0472	$0.0471	$0.0307	$0.0307
2019 ERRA Refund											-$0.0082		
Proposed Rates	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0306	$0.0307	$0.0307
Capped?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
Proposed % Rate Change	21%	18%	17%	17%	16%	16%	16%	16%	16%	16%	-9%	-24%	

Based on my review of PG&E's application, supporting workpapers, and responses to discovery I make the following recommendations to bring PG&E's request in line with prior Commission rules, regulations, resolutions, decisions, and just and reasonable ratemaking:

- PG&E should rely on the authorized generation revenue requirement as approved in a final decision in PG&E's most recent Phase I General Rate

Case ("**GRC**") to calculate the 2021 Indifference Amount until a final decision is reached in A.18-12-009.

- Like its proposal for GRC costs, PG&E's request to include wildfire-related insurance costs tracked in the Wildfire Expense Memorandum Account ("**WEMA**") should be rejected as premature.
- Forecast Retained RA value should be corrected to include capacity from RA contracts through which PG&E purchased local capacity to serve bundled customers.
- PG&E should adjust the PABA balance to comply with D.20-02-047 and reflect the ordered adjustment related to Actual Retained RPS quantities.
- PG&E's Application did not sufficiently support accruals to its PABA balance. Future applications should be accompanied by additional detail supporting the year-to-date PABA balance and testimony explaining material deviations from PCIA forecasts.
- PG&E should correct a miscalculation within its Green Tariff Shared Renewables ("**GTSR**") and Enhanced Community Renewables ("**ECR**") rates to reflect only (1) capacity retained to serve its bundled customers and (2) the billing determinants from its bundled customers. This correction increases the Resource Adequacy charge for E-GT and E-ECR customers from $0.00798/kWh to $0.01312/kWh.
- PG&E must ensure Energy Supply Administration ("**ESA**") costs are not double-counted in the PCIA and CAM.

- PG&E's should include in its November Update the funding for other CCAs' offerings of low-income and disadvantaged communities solar programs.

Adopting these recommendations results in a PCIA revenue requirement of $2,537.6 million compared to PG&E's proposal of $2,802.6 million, a 9.5% reduction. For unbundled customers the PCIA revenue requirement would be $1,713.5 million rather than the $1,864.3 million[12] proposed in PG&E's testimony, an 8.1% reduction. For bundled customers the PCIA revenue requirement would be $824.1 million rather than the $938.2 million[13] proposed in PG&E's Supplemental Testimony, a 12.2% reduction. The impact of each adjustment affecting PCIA revenue requirement is itemized in Table 2 below:

Table 2: Joint CCAs Proposed Adjustments

Adjustment	PCIA Revenue Requirement Impact
Include Approved GRC Costs	-$104.7 million
Exclude Preliminary WEMA Costs	-$131.1 million
Correct Forecast Retained RA Capacity	[redacted]
Correct Actual Retained RPS per D.20-02-047	-$23.9 million

The PCIA rates resulting from these changes are shown by vintage and rate class in Table 3.

12 *See* PG&E Supplemental Testimony, Table 19-6.
13 *Id*.

Table 3: Joint CCAs Adjusted PCIA Rates

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2020 Capped	$0.0243	$0.0273	$0.0297	$0.0296	$0.0316	$0.0321	$0.0319	$0.0318	$0.0317	$0.0317	$0.0338	$0.0406	
2020 Uncapped	$0.0326	$0.0394	$0.0414	$0.0431	$0.0437	$0.0438	$0.0439	$0.0434	$0.0427	$0.0420	$0.0406	$0.0406	
2021 Capped	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0388	$0.0456	
2021 Uncapped	$0.0321	$0.0383	$0.0400	$0.0417	$0.0421	$0.0423	$0.0425	$0.0424	$0.0433	$0.0436	$0.0434	$0.0270	$0.0270
2019 ERRA Refund											-$0.0082		
Proposed Rates	$0.0293	$0.0323	$0.0347	$0.0346	$0.0366	$0.0371	$0.0369	$0.0368	$0.0367	$0.0367	$0.0306	$0.0270	$0.0270
Capped?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
Proposed % Rate Change	21%	18%	17%	17%	16%	16%	16%	16%	16%	16%	-9%	-34%	

As seen above, even taking into account the Joint CCAs' adjustments, the adjusted PCIA rates would still be capped for all vintages except 2020 and 2021.

The rates in Table 3 are preliminary and remain subject to change as the PCIA revenue requirement is updated throughout this proceeding. In fact, the final increase to the PCIA revenue requirement and resulting uncapped rates is likely to be substantially greater than the proposal in the Application given the current status of the PABA year-end balance. In PG&E's August 2020 ERRA Monthly Activity Report[14] the year-to-date PABA under-collection had reached a staggering $1,167.4 million by the end of July. Removing the balance in the PCIA Subaccount, which is not included in determining 2021 PCIA revenue requirement, results in a July 2020 balance of $948.3 million[15] over 75% higher than the $537.8 million projected as the year-end PABA balance in the Application (prior to the application of an ERRA-related credit).[16] Given these increases,

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14 *See PG&E Energy Resource Recovery Account Activity Report*, p. 4, "Total PABA Ending Balance" (August 2020).

15 *See* PG&E's response to Joint CCA DR 4.01, Confidential Attachment 1. Total balance not marked as confidential.

16 It is possible the billion-dollar actual balance will be reduced over the rest of 2020, but the difference is enormous, especially given the fact that PG&E's forecast for the remainder of 2020 assumes no load reduction from COVID-19.

it is important the Joint CCAs' recommended adjustments are accounted for in any subsequent update.

As discussed in more detail below, the proposed 2021 Indifference Amount is more than 6 times larger than in 2013 – an annual growth rate of 26%. Increases in the costs of utility-owned generation ("**UOG**") and decreases in the value of PG&E's portfolio have driven continued increases to the PCIA, with 98% of the above-market costs projected in 2021 attributed to PG&E's Legacy UOG and resource vintages prior to 2013. The other key factor is that, based on the Commission's administrative measure of short-term market value, the value of PG&E's portfolio has fallen at a rate of 9% per year and is less than half the dollar value than it was in 2013. Notably, for the first time in the 2021 forecast, market value as determined in the PCIA is less than the fixed costs of PG&E's portfolio of utility-owned resources.

II. THE PCIA, THE PABA AND THE PUBA

A. Background and Explanation of These Complex Rate Components

CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA customers pay CCA-specific generation rates. CCA rates are partially influenced by local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges ("**NBCs**"), including the PCIA and the CAM, the 2021 levels of which will be determined in this proceeding.

The Commission adopted the PCIA to ensure that when customers of investor-owned utilities ("**IOUs**") depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[17]

The PCIA is derived from the utility's Indifference Amount, which is updated annually in each IOU's ERRA proceeding. The Indifference Amount is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio.

Total Portfolio Cost includes capital investment recovery and fixed maintenance costs determined in a General Rate Case ("**GRC**") for utility owned generation, purchased power such as that from power purchase agreements ("**PPAs**"), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator ("**CAISO**") grid charges and revenues, net of any sales.[18]

Portfolio Market Value is derived from total eligible generation in megawatt-hours (MWh) multiplied by the Market Price Benchmarks ("**MPBs**") ($/MWh), an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[19] Portfolio Market Value consists of three principle

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17 *See also* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (September 25, 2017), D.18-10-019, p. 3 (October 11, 2018).

18 R.07-05-025, D.11-12-018, pp. 8-9 (December 1, 2011).

19 D.19-10-001, p. 6 (October 10, 2019) ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.").

components: Energy Value, RPS Value, and RA Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation energy-only component of a utility portfolio for a given year.[20]

- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[21]

- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[22]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[23] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[24]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index", "Brown Power component", "Brown Power Adder", or "Brown Power benchmark."[25]

- RPS Adder is the MPB that reflects the estimated incremental value of each unit of RPS-eligible energy in $/MWh.[26]

- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-month). The RA Adder has three subcomponents, reflecting each type of RA product required for compliance with the RA program: system, local and flexible.[27]

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20 *Id*.
21 *Id*.
22 *Id*.
23 *Id*.
24 *Id*.
25 *Id*., p. 7.
26 *Id*.
27 *Id*.

Finally, each generation resource and departing customer is assigned a "vintage." A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned to vintage years according to the date departing bundled IOU service.[28] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g. vintage 2021 in the current application). Each vintage is assigned a separate Indifference Amount[29] and customers are responsible for the cumulative PCIA rates for their vintage.

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. That decision approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and departing load customers. This true-up now occurs via the PABA, a rolling true-up between the forecasted costs and revenues used to determine the Indifference Amount and the actual costs and revenues PG&E realizes during the year related to its PCIA eligible resource portfolio.

PG&E's PCIA rates for 2021 will be set in this proceeding based on two key components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2021 and the forecasted market value of PG&E's generation portfolio in 2021; and (2) the 2020 year-end balance in the PABA.[30]

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[28] Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.

[29] D.11-12-018, p. 9 (December 1, 2011).

[30] Because the true-up for 2020 occurs during 2020, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's July Application includes an estimate of the 2020 year-end PABA balance comprising a combination of actual entries from January through April 2020 and a projection of activity from May through December 2020.

The Indifference Amount and the year-end PABA balance are added together to form the revenue requirement underlying PCIA rates. This year, PG&E is also proposing to transfer the year-end ERRA balance into the latest PABA vintage which would then be rolled into PCIA rates. The total proposed PCIA revenue requirement of $2.8 billion is shown for each vintage in Table 4.

Table 4: PCIA Revenue Requirement by Vintage ($000s)

Vintage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2021 Indifference Amount Forecast	$2,241,422	$294,065	$85,776	$66,466	$19,756	$567	$3,725	$3,096	$4,083	$9,966	$10,859	$2,405	$2,742,186
2020 PABA Balance	$351,310	$144,918	$31,213	$52,705	$14,159	$7,476	$14,039	-$6,440	$45,765	$3,267	-$12,198	-$108,415	$537,799
2020 ERRA BA Balance												-$471,336	-$471,336
2019 ERRA Refund											-$6,096		-$6,096
Total PABA Revenue Requirement	**$2,592,732**	**$438,983**	**$116,988**	**$119,171**	**$33,916**	**$8,043**	**$17,764**	**-$3,344**	**$49,849**	**$13,233**	**-$7,434**	**-$577,346**	**$2,802,552**

The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage, *i.e.*, the year unbundled customers left PG&E's service,[31] and their rate class using the allocation factors from PG&E's most recently approved GRC.[32]

Decision 18-10-019 also limited "the change of the PCIA from one year to the next. Starting with forecast year 2020, the cap level of the PCIA rate should be set at $0.005/kWh more than the prior year's PCIA, differentiated by vintage."[33] If departing load rates would exceed the rate cap in a given year, bundled customers rates are increased instead to 'finance' the amount above the cap. A separate balancing account, the PCIA Under-collection Balancing Account ("**PUBA**"), was also established to record the shortfall in revenue charged to departing load customers due to PCIA rates being limited by the $0.005/kWh cap in annual rate changes. Unbundled customers are

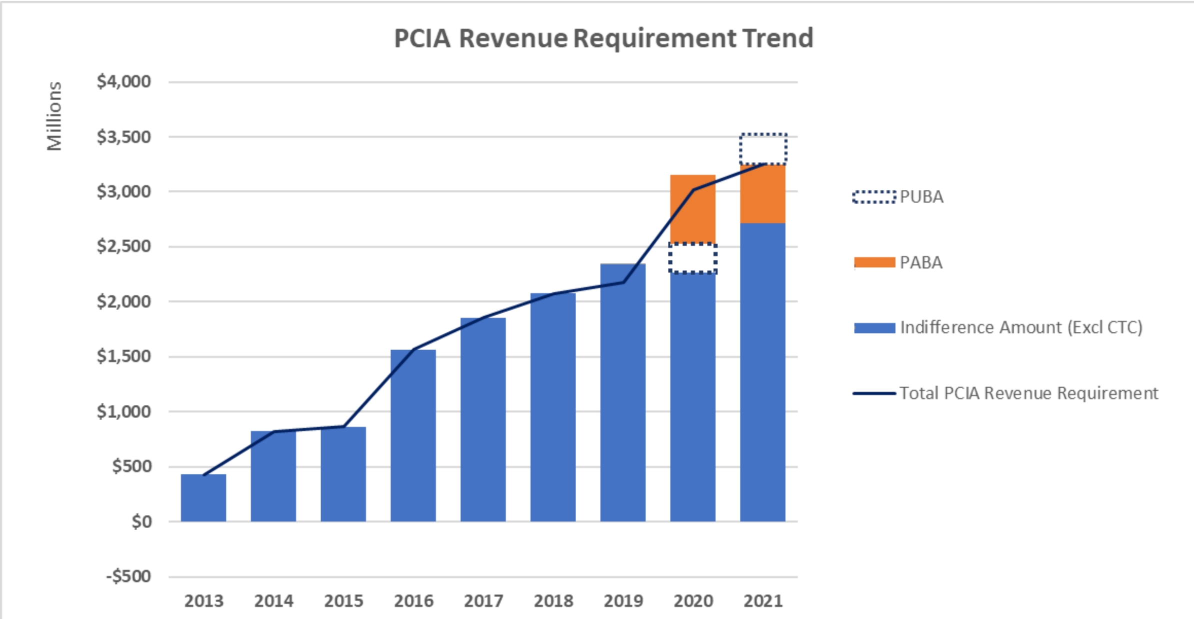
31 D.11-12-018, p. 9 (December 1, 2011).
32 D.18-10-019, p. 122 and Ordering Paragraph 4 (October 11, 2018).
33 *Id.*, Conclusions of Law 19-20, Ordering Paragraph ("OP") 9(a)-(c) (October 11, 2018).

responsible to pay for the shortfall recorded to PUBA, plus interest, to compensate bundled customers for having paid for the amount in excess of the cap.

B. Status of the PCIA: Increases in the Costs of Utility-Owned Generation and Decreases in the Value of PG&E's Portfolio Drive Continued Increases to the PCIA.

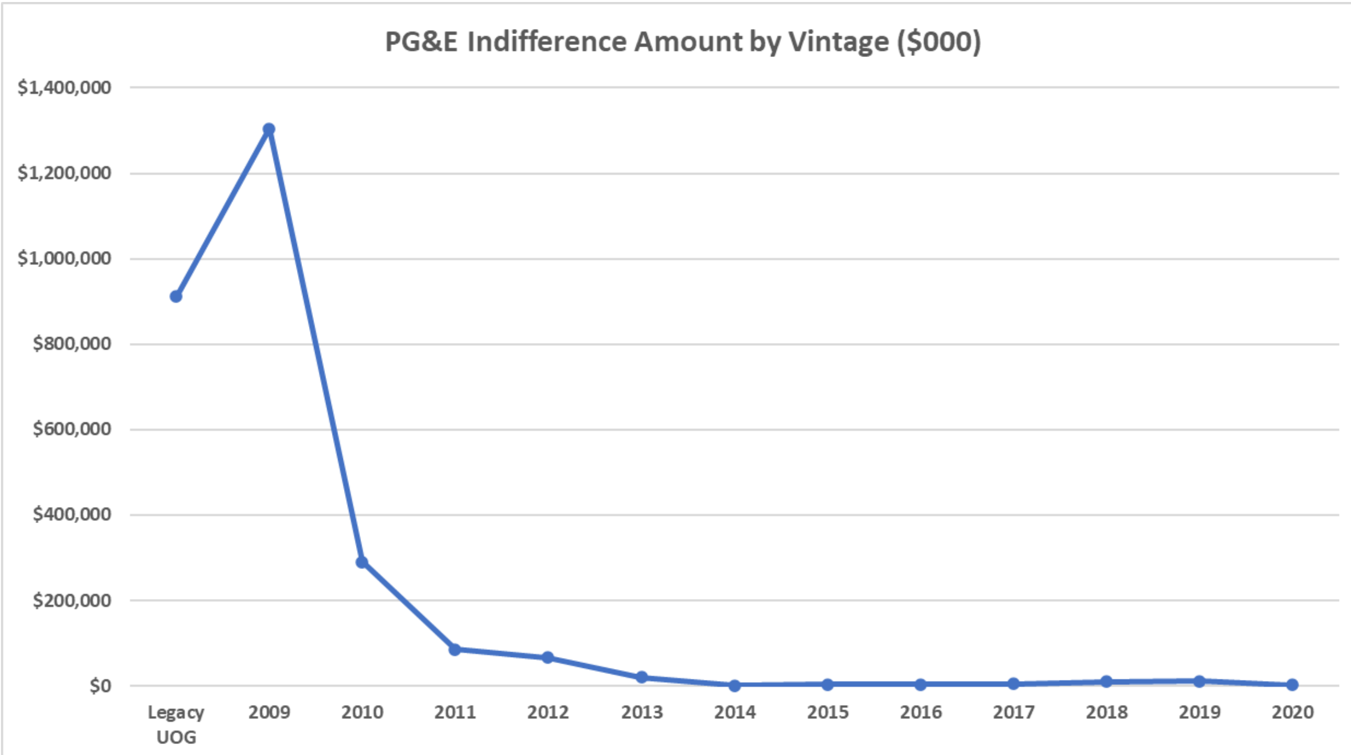
PG&E's 2021 ERRA Forecast application continues the trend of significant annual increases to the PCIA. The proposed 2021 Indifference Amount is more than 6 times larger than in 2013 – an annual growth rate of 26%. The advent of the PABA in D.18-10-019 tacked on an additional $621 million to the PCIA revenue requirement in 2019, a 25% increase in a single step. Even with the PCIA rate cap, PCIA rates for most departing load customers will increase at least 16% in 2021. The PCIA rate cap first took effect with the 2020 PCIA rates. As a result, departing load customers temporarily benefitted from the protection provided by the cap. That benefit must be paid back, however, and future PCIA rates are likely to reflect the recovery of the balance currently accumulating in the PUBA. Figure 1 below illustrates the rapid increase in the PCIA revenue requirement since 2013. It also demonstrates the step change occurring with the introduction of the PABA, and the potential impact of shifting the timing of cost recovery from departed load customers through the PUBA.

Figure 1: PCIA Revenue Requirement 2013 - 2021



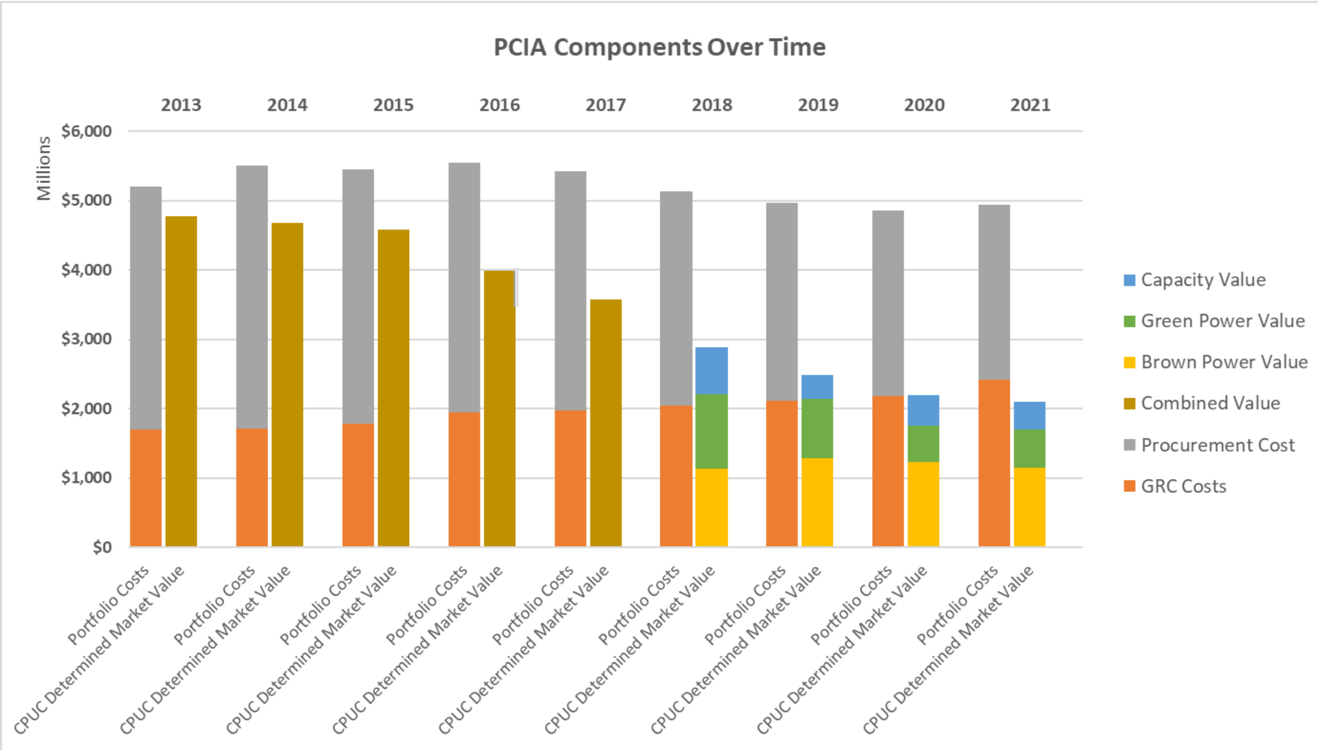
Fundamentally, the PCIA, PABA, and PUBA all exist to recover the above-market cost, or the Indifference Amount, of PG&E's generation resource portfolio. Comparing the Indifference Amount for each individual vintage, as done in Figure 2, reveals that 98% of the above market costs projected in 2021 are attributed to PG&E's Legacy UOG and resource vintages prior to 2013.

Figure 2: Indifference Amount by Vintage



The growth in the Indifference Amount since 2013 can be attributed to a sharp reduction in the Commission's administratively determined market value of PG&E's resource portfolio and a steady increase in GRC-related costs of the UOG resources. Figure 3 compares the change in major PCIA components—including GRC and procurement costs, offset by portfolio market value—between 2013 and 2021.

Figure 3: PCIA Components Over Time



Since 2013 total portfolio costs have remained relatively flat, but the stability in total costs masks the offsetting changes in fixed GRC costs versus variable production costs. As shown in Figure 3, GRC costs have grown 5% annually since 2013 while variable production costs have fallen at an annual rate of 4%. Over that same period, the CPUC's changing administrative measure of short-term market value has fallen at a rate of 9% per year and is less than half the dollar value than it was in 2013. Notably, for the first time in the 2021 forecast, total portfolio market value is less than the GRC-related fixed costs of PG&E's portfolio.

III. ISSUES RELATED TO THE CALCUATION OF THE 2021 FORECASTED INDIFFERENCE AMOUNT.

A review of PG&E's testimony and workpapers supporting its calculation of the Indifference Amount reveals PG&E included preliminary data from its pending GRC and separate application to recover wildfire-related insurance costs. Addressing these issues will ensure the PCIA rates are based solely on Commission-approved costs.

A. PG&E's Utility Owned Generation Costs Should be Calculated Using Commission-Authorized Generation Base Revenue Requirement.

In ERRA forecast proceedings, the generation base revenue requirement, i.e. non-fuel costs of PCIA-eligible utility-owned generation, included in the Indifference Amount calculation should be as approved in a final decision in PG&E's most recent Phase I GRC. PG&E indicates in its testimony that it relied on a settlement agreement reached in its 2020 GRC to calculate the generation base revenue requirement included in the 2021 Indifference Amount.[34] The Joint CCAs confirmed through discovery that PG&E's proposed PCIA rates in this application are based on the proposed generation costs from PG&E's pending 2020 Phase I GRC, A.18-12-009, which has not yet been finalized or approved by the Commission.[35]

In last year's 2020 ERRA Forecast proceeding, PG&E also filed its application using proposed and unapproved generation costs from the same Phase I GRC, A.18-12-009, "for rate-setting purposes."[36] The utility eventually acquiesced to using the approved generation costs from its 2017 GRC, adjusted for subsequent federal income tax reform, to set the PCIA.[37] Here again, authorized generation base revenue requirement used to calculate the 2021 PCIA should be based on PG&E's 2017 GRC decision, D.17-05-013, until a final decision is reached in A.18-12-009. If a Commission

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34 *See* PG&E Prepared Testimony, Chapter 9, at 9-5:12-20.

35 *See* PG&E Response to Joint CCAs DR 2.13.

36 *See, e.g.,* A.19-06-001, *Opening Brief of the Joint Community Choice Aggregators*, pp. 33-34 (October 21, 2019).

37 The generation base revenue requirement approved in D.17-05-013 was reduced for the impact of the 2017 Tax Cuts and Jobs Act as approved by the Commission in D.19-08-023.

decision in A.18-12-009 is not reached in time for inclusion in the November Update, PG&E should be required to include the generation base revenue requirement approved in D.17-05-013, as adjusted tax reform, in the calculation of the Indifference Amount. Replacing the preliminary GRC costs with the approved amounts reduces the Indifference Amount by **$104.7 million**.[38]

B. PG&E's Request for Recovery of Insurance-Related Costs during 2021 in its WEMA Proceeding Has Not Been Approved.

Like its proposal for GRC costs, PG&E's request to include $131 million in wildfire-related insurance costs in the Indifference Amount for 2021 should be rejected as premature. In D.18-06-029, the Commission established the Wildfire Expense Memorandum Account to track certain incremental wildfire liability costs, but it did not address cost allocation or cost recovery issues with respect to the account.[39] The corresponding Advice Letters establishing WEMA similarly do not directly address cost recovery issues,[40] although they do include guidance that cost allocation shall be the same as that for "Administrative & General costs" in "PG&E's GRC at the time the activity is recorded in the account."[41]

In A.20-02-004, PG&E seeks to recover $498.7 million of insurance costs recorded in the WEMA for 2017-2019 over a one-year period, commencing in January

38 Including RF&U impact.

39 *See generally* D.18-06-029; *id.*, Conclusion of Law 5 ("The specific criteria for rate recovery of costs recorded in the WEMA should be addressed in separate rate recovery proceedings.").

40 *See* Advice Letter 3991-G/5331-E (August 15, 2018) ("AL 3991-G/5331-E"); Advice Letter 4016-G/5386-E (October 23, 2018) ("AL 4016-G/5386-E").

41 AL 3991-G/5331-E, Gas Preliminary Statement Part EE and Electric Preliminary Statement Part HL; AL 4016-G/5386-E, Gas Preliminary Statement Part EE and Electric Preliminary Statement Part HL (stating "the payments and reimbursements made by PG&E and the associated insurance or third-party reimbursements will be allocated between electric and gas in the same manner as Administrative & General costs are allocated as approved in PG&E's GRC at the time the activity is recorded in the account.").

2021.[42] The costs are incremental to those previously authorized in PG&E's 2017 GRC and currently sought in PG&E's 2020 GRC.[43] The Joint CCAs confirmed through discovery that PG&E's proposed PCIA rates in this application are based on the utility's request in A.20-02-004 which is currently pending before the Commission.[44] PG&E's Prepared Testimony attributes $131 million of the $498.7 million of wildfire-related insurance costs to generation and requests those costs be included in the Indifference Amount for 2021.[45]

As noted in the prior section, all calculations and entries in this proceeding must be based on adopted Commission rules, regulations, resolutions and decisions for all customer classes.[46] Not only is there no decision on whether PG&E can recover the insurance costs at issue, there is no decision on whether the $131 million figure is the correct amount to allocate to generation, and there is no guidance regarding the allocation of those costs across vintages. In fact, the Commission has not yet issued a Scoping Ruling in A.20-02-004, meaning there is no procedural schedule to indicate whether a decision may be forthcoming prior to the November Update. While PG&E states "PG&E's November Update will reflect the status of that application,"[47] the utility should not have included these costs in the instant Application. Removing the preliminary GRC costs with the approved amounts reduces the Indifference Amount by **$131.1 million.**[48]

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42 A.20-02-004, *Application of Pacific Gas and Electric Company (U 39 M) to Recover Insurance Costs Recorded in the Wildfire Expense Memorandum Account*, p. 1 (Feb. 7, 2020).

43 *Id*.

44 *See* PG&E Response to Joint CCAs DR 2.13.

45 *See* PG&E Prepared Testimony at 9-4:24 to 9-5:4 and 9-6:1-3.

46 *See, e.g.,* 2020 Scoping Ruling at 2-3.

47 *See* PG&E Prepared Testimony at 1-5, n. 5, and 9-6:1-13.

48 Including RF&U impact.

C. PG&E Erroneously Excluded Capacity from RA Purchases from its Calculation of Retained RA.

As described earlier, one component of PG&E's resource portfolio market value is RA Value - the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year. For purposes of the Indifference Calculation, each unit of capacity in a utility resource portfolio is determined to fall within one of three buckets: Forecast Retained RA, Forecast Sold RA, and Forecast Unsold RA. Forecast Retained RA is capacity needed to satisfy the utility's Resource Adequacy obligations for bundled customer load, and the value of Retained RA from PCIA-eligible resources is counted as a credit against portfolio costs when calculating the Indifference Amount.[49] Retained RA value is determined by multiplying the RA Adder, in dollars per kilowatt ($/kW), by the Forecast Retained RA capacity.

In response to Joint CCA DR 4.11, PG&E confirmed that the capacity from six different contracts to purchase Local RA capacity was inadvertently omitted from the Retained RA volume and the associated Forecast Retained RA value, despite the cost of the contracts being included in PCIA-eligible portfolio costs.[50] Excluding these contracts' capacity from the calculation of RA Value undervalues PG&E's resource portfolio and increases the Indifference Amount. Correcting the Indifference Amount calculation to reflect this Local RA capacity in the value of Retained RA reduces the Indifference Amount by [redacted][51] based on the Local RA Adder authorized in D.20-02-047. PG&E indicated it would include the contracts' capacity in Forecast Retained

[49] Retained RA value is credited toward PCIA revenue requirement, with a corresponding increase in ERRA revenue requirement, reflecting bundled customers' responsibility for the cost of PG&E's RA compliance.

[50] *See* PG&E confidential response to Joint CCA DR 4.11

[51] Including impact of line losses and RF&U.

RA for its November Update. At that time PG&E will also update the RA Adder to reflect the newly calculated MPBs for 2021, and the amount of this adjustment will change accordingly.

D. PG&E Clarified its Projection of Unsold RA Capacity for 2021.

When forecasting the value of PG&E's generation portfolio in 2021, any capacity that is anticipated to (1) not be used for compliance with PG&E's RA requirements and (2) remain unsold despite being offered for sale, *i.e.*, Forecast Unsold RA, is valued at zero dollars.[52] PG&E's Prepared Testimony describes how the utility's forecast assumed that 10% of its RA capacity will remain unsold in 2021.[53] In contrast, PG&E's workpapers appeared to reflect zero Forecast Unsold RA capacity in 2021.[54] In response to discovery,[55] and in its August Supplemental Testimony,[56] PG&E confirmed that the PCIA revenue requirement included zero Forecast Unsold RA capacity. PG&E corrected its testimony to read, "For the purposes of the July 1 forecast, placeholder values of zero were used in the PCIA benchmark calculation; these values will be revised in the November forecast when there will be a more complete accounting of the number and magnitude of RA sales executed in 2020 for 2021."

The Joint CCAs support a forecast assumption of zero Forecast Unsold RA for 2021 due to the tightness in the RA market and the recent changes to the RA procurement regime. The Commission's Energy Division issued a State of the Resource Adequacy

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52 D.19-10-001, Ordering Paragraph 2, Attachment B, Table II.
53 *See* PG&E Prepared Testimony at 9-4:7 and n.13.
54 *See* PG&E Workpaper entitled: 09.ERRA_2021Forecast_WP_PGE_20200701_Ch09_CONF.xlsx, tab 'CONF CAL Table 9-1'.
55 *See* PG&E response to Joint CCA DR 3.14
56 *See* PG&E Supplemental Testimony at 7:1-17.

Market – Revised report ("RA Market Report"), wherein it reported on RA procurement for the 2019 compliance period and information on RA deficiencies.[57] The RA Market Report documents the capacity used by LSEs to meet local, system, and flexible RA requirements for 2019. Energy Division's overall conclusion is that "the RA market remains tight"[58] and it stated, "we can expect that the market will continue to tighten."[59]

During 2019, many LSEs reported RA deficiencies, including shortages in local, system, and flexible RA that persisted through 2019. In particular, the RA Market Report cites that on October 31, 2018, 10 LSEs submitted local waiver requests due to their inability to procure sufficient local RA to meet their 2019 year ahead requirements. Of the Joint CCAs, four were included in the group filing local waivers on October 31, 2018: East Bay Community Energy, Peninsula Clean Energy Authority, San Jose Clean Energy, and Sonoma Clean Power Authority. East Bay Community Energy and San Jose Clean Energy were also both unable to meet 100% of their year-ahead system RA obligations despite making reasonable efforts to do so. East Bay Community Energy was also unable to meet 100% of its 2020 local and system RA requirements and submitted a local waiver request on October 31, 2019.

Given the Commission's outlook on future market conditions, the Joint CCAs agree with forecasting a zero amount of Unsold RA capacity for 2021.

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57 Updated Energy Division Resource Adequacy Market Report (attached hereto as Attachment C).

58 *Id.*, p. 40.

59 *Id.*, p. 41.

IV. ISSUES RELATED TO PG&E'S BALANCING ACCOUNTS

PG&E's proposed PCIA revenue requirement and 2021 PCIA rates are affected by three main balancing accounts: 1) PABA, 2) ERRA, and 3) PUBA.

PABA constitutes a rolling true-up between the forecasted components of the Indifference Amount used to set the PCIA rates in a year and the actual costs and revenues PG&E experiences during that year, which, in this case, is 2020. Any resulting over- or under-collection in the PABA, by vintage, in 2020 is added to the PCIA revenue requirement used to establish the 2021 PCIA rates. As noted above, the costs and revenues forecasted and recorded to PABA apply to both bundled and unbundled customers.

ERRA is a rolling true-up of PG&E's actual costs to meet bundled service customers' energy and ancillary service requirements through the CAISO market, along with the fuel and purchased power costs of any resources that are not eligible for recovery in the PABA or other mechanisms (e.g. CAM). The ERRA also includes the imputed cost[60] of RECs and RA products retained to meet compliance requirements for bundled customers, with an offsetting credit recorded to the PABA. Customers receiving bundled service from PG&E during the time costs accrue to the ERRA balancing account are responsible for subsequent recovery, or refund, of the true-up balance.

The third balancing account, PUBA, is a record of the shortfall in revenue charged to departing load customers due to PCIA rates being limited by the $0.005/kWh cap in annual changes adopted in D.18-10-019. That decision limited "the change of the PCIA from one year to the next. Starting with forecast year 2020, the cap level of the

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60 An "imputed cost" in PG&E's ERRA forecast proceeding is a cost that is assigned a value via an MPB as opposed to a cost obtained via a market-based purchase.

PCIA rate should be set at 0.5 cents/kWh more than the prior year's PCIA, differentiated by vintage."[61] Any amount beyond the cap is tracked in the PUBA, and only unbundled customers are responsible for the shortfall recorded to PUBA.

A. PG&E Presents a Significant PABA Under-Collection Based on Unverifiable Data for 2020 Actuals to Date.

PG&E projects the PABA will have an under-recovered balance of $537.8 million at the end of 2020, but provided few details regarding this under-collection, simply listing monthly dollar totals for recorded costs and revenues by category. This level of detail prevents the Commission and parties from determining whether those amounts would result in just and reasonable rates and from understanding at a basic level the elements driving the under-collection.

Since its inception in 2019, the PABA has been a major contributor to the total PCIA revenue requirement, causing an incremental upward bump in already increasing PCIA rates. In addition to being a large contributor to PCIA revenue requirement, the PABA balance has proven to be unpredictable, fluctuating by hundreds of millions of dollars through the pendency of the ERRA application process. For example, PG&E began the year 2020 with a PABA balance of $713.7 million. If PCIA rates were implemented on January 1 and everything went according to forecast during 2020, the PABA balance should be reduced to $0 by the end of the year. By April 2020, however, the balance had already risen to $793.8 million. In its July Application, PG&E projected that the PABA balance would decline over the course of the year, ending 2020 with a

[61] R.17-06-026, D.18-10-019, Conclusions of Law 19-20, Ordering Paragraph ("OP") 9(a)-(c) (October 11, 2018).

balance of $537.1 million.[62] So far, the actual PABA balance has remained higher than expected. At the time this testimony was prepared the latest detailed results available to the Joint CCAs—actual result through July 2020—showed that the PABA balance had reached a staggering $948.3 million,[63] $141.1 million higher than projected at that point. On September 21, 2020, PG&E filed its Monthly ERRA Activity report with the Commission, and the public version of that report appears to show the August 2020 PABA balance dropping to $793.2 million.[64] Figure 4 illustrates the variability in the monthly PABA balance in 2020 and the deviation of the actual balance from the forecast included in PG&E's Application.

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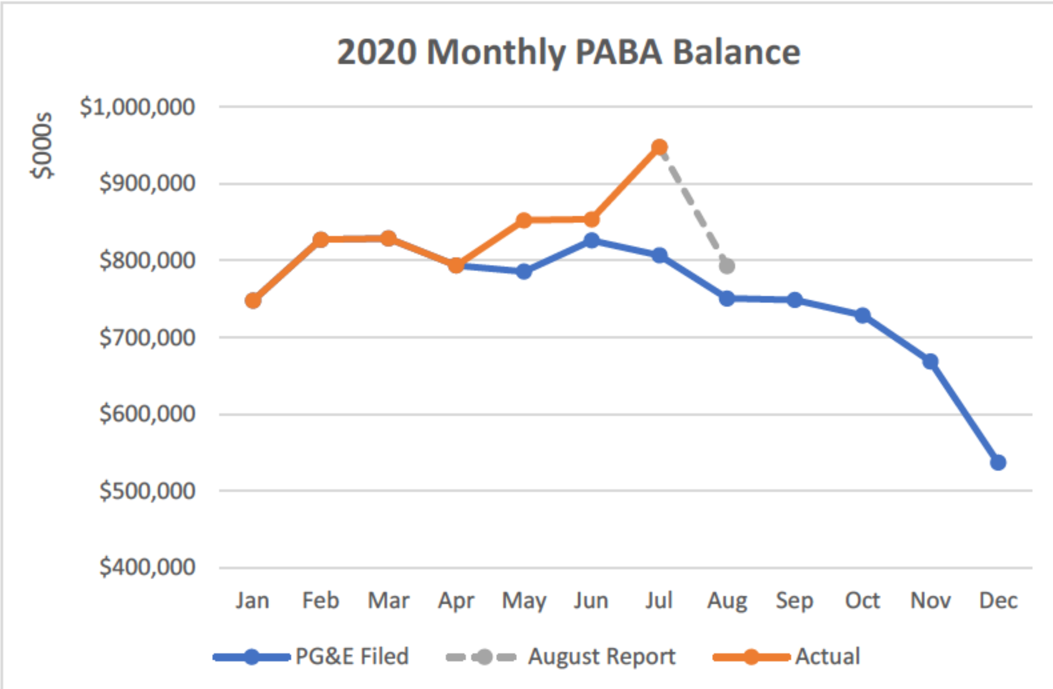
62 *See* PG&E Prepared Testimony, Chapter 14, Table 14-2. The referenced 2020 year-end PABA balance excludes the proposed transfer of a $477.4 million credit from the ERRA.

63 *See* PG&E's response to Joint CCA DR 4.01, Confidential Attachment 1. Total balance not marked as confidential. The $948.3 million balance excludes PCIA Subaccount. Including the PCIA Subaccount, the July 2020 PABA balance was $1,167.4 million.

64 Excluding the PCIA Subaccount.

Figure 4: PG&E Monthly PABA Balance



PG&E provided a brief explanation of the primary drivers contributing to the PABA under-collection in its Prepared Testimony. According to PG&E, the two main drivers of the under-collection in 2020 are 1) late implementation of the 2020 PCIA rates, and 2) lower than expected CAISO revenue for generation from PCIA-eligible resources. PG&E cites lower retail sales from January to April due to mild weather and the impacts of the COVID-19 pandemic and its disputed adjustment to Unsold RPS value stemming from D.20-02-047 as contributing to under-collections.

The sheer magnitude of the PABA, its inclusion in the 2021 PCIA revenue requirement, and the growing discrepancy between recorded costs and PG&E's projections underscore the importance of verifying the reasonableness of PG&E's PABA balance in this Application. Large deviations between actual and forecast results spotlight potential areas for investigation. Often such investigation leads to the discovery of errors or opportunities to improve forecasts, all of which is in the interest of both bundled and unbundled customers.

Through discovery the Joint CCAs worked with PG&E to obtain data, including, importantly, the volumes underlying the recorded dollar amounts in PG&E's workpapers, necessary to perform an analysis of the growing PABA balance. At the time this testimony was filed, PG&E had provided the details of recorded amounts from January through July 2020. Confidential Table 6 below compares the 2020 forecasted PCIA revenue requirement to the 2020 PABA as included in PG&E's initial Application (i.e. actual results through April 2020 and PG&E's projection through December 2020). The table highlights major PABA categories and variances, and the discussion that follows is organized according to major PABA category.

Confidential Table 6:
As-Filed 2020 PABA Variance Analysis (Actuals Through April)

[redacted]

1. Customer Revenue

As expected, projected customer revenue in 2020 is well short of forecast and is expected to be the single largest contributor to the under-collected PABA balance at the end of 2020. Based on the data provided by PG&E, approximately [redacted] of the revenue under-collection is due to delayed implementation of new PCIA rates (which didn't take effect until May 2020) and another [redacted] to lower than expected sales volumes. PG&E explained that the impact of the COVID-19 pandemic on customers sales is reflected in the actual results through April 2020 but has not been accounted for in the balance of the year projection. Even so, the annual retail sales volumes relied on to compute the projected year-end PABA balance are over [redacted] lower than forecast.

2. Energy Value

Confidential Table 6 confirms that the second largest driver of continued PABA under-collection in 2020 is a drop in brown power market value, contributing over [redacted] to the PABA balance remaining at the end of 2020. The reduction in annual value is due predominantly to a nearly [redacted] reduction in energy sales in the CAISO market. PG&E's projections for the year show market prices close to forecast. However, realized market prices from January through April averaged [redacted], [redacted] lower than the $34.14/MWh Brown Power MPB used for the 2020 ERRA Forecast. These prices are relatively consistent with reported average NP-15 market prices and not unexpected given the market conditions early in the year. PG&E's forecasted market price for the balance of the year is [redacted], [redacted] higher than the Brown Power MPB.

3. RPS Value

Confidential Table 6 shows that, at the time of filing, projected RPS value in 2020 was also expected to be a material driver of PABA under-collection. Total RPS Market Value for 2020 is expected to be approximately [redacted] lower than forecast. The reduced value is driven by lower RPS sales volumes at a lower than expected price. Expected RPS sales volumes for 2020 are [redacted] lower than forecasted, and the realized price of RPS sales is expected to be only [redacted] compared to the $17.35/MWh RPS Adder used in the 2020 ERRA Forecast.

4. RA Value

Confidential Table 6 shows a relatively small reduction to RA value projected for 2020. The change is due to the change in volume of Unsold RA valued at $0 in the PABA.

5. Portfolio Costs

Total portfolio costs are approximately 2% lower than forecast driven by a reduction in generation volumes from owned and purchased resources. The reduction in generation volume is consistent with the lower market prices relative to the forecast. As shown in Confidential Table 6, GRC-related costs are being recorded as expected and variable costs of production are lower than projected. The fixed nature of GRC-related costs reinforces the trends identified earlier in my testimony; despite lower demand for

PG&E resources, GRC costs do not vary with demand and have been increasing on an annual basis.

In total, at the time of PG&E's filing, the combination of lower customer revenues and lower energy value made up more than the entire under-collection projected to remain in the PABA at the end of 2020. Since the filing, additional actual results show that the same categories are contributing to the PABA variance but with an even more pronounced effect. Confidential Table 7 below is an updated comparison of the 2020 forecasted PCIA revenue requirement to the 2020 PABA, now with actual results from January through July combined with PG&E's projected activity through the end of 2020 (as originally filed).

Confidential Table 7:
Updated 2020 PABA Variance Analysis (Actuals Through July)

[redacted]

Given the unique circumstances facing California's economy in general since early 2020 and the impact on electricity consumption and market conditions, the trends observed in the variance analyses above appear largely in alignment with expectations. Lower customer load and lower market prices during the state's response to the COVID-19 pandemic have contributed materially to PABA under-collection in 2020. Changed circumstances in later months, including the heat wave experienced by many Californians during August, may relieve some pressure on the PABA under-collection, and will certainly have an impact on the comparisons presented here. PG&E's rebuttal testimony and November Update filing should provide additional insight into the most recent PABA actuals.

The summary analyses I present here illustrate, at least at a high level, the underlying causes of higher than expected balances in the PABA. Such understanding is critical for the Commission and other parties to reach a conclusion that the 2021 PCIA rates, which will include the PABA true up, are accurate and reasonable. Understanding what is happening to the PCIA in a particular year, and over a period of several years, can inform the Commission regarding potential structural changes that should be made to the PCIA framework. Transparent and timely access to data supporting the utility's requested annual rate increase can reduce conflict in the ERRA proceedings and minimize unexpected outcomes in the November Update. As customer-facing load serving entities, it is also imperative that CCAs are granted access to the data required to complete these analyses on a timely basis in order to anticipate and plan for potential rate impacts on their customers and to operate their own programs to serve their customers.

The Joint CCAs sought PG&E's cooperation in the discovery process to provide monthly actual volumetric data, by category, underlying the PABA actuals in this proceeding. The Joint CCAs were finally provided volumetric data underlying the recorded PABA balances on September 17, 2020, more than two months after the Application was made and only one week prior to the deadline for filing intervenor testimony. The data provided is useful, but it is still summarized in a way that prevents a review of each resource category and the impact on PCIA rates in this Application.

Furthermore, the discovery process is not an ideal avenue in which to obtain this data given the abbreviated schedule required in the ERRA forecast proceeding. In future ERRA forecast applications, PG&E should be required to provide in its confidential workpapers, and in routine updates throughout the proceeding, the data required to review actual PABA activity. Such data should include:

- Confidential versions of the monthly ERRA/PABA/PUBA reports.
- Detail supporting the monthly PABA reports, including subcategories for summarized line items such as UOG costs and Contracts (e.g. provide by resource type, and whether RPS or non-RPS eligible).
- Volumetric quantities underlying each relevant dollar figure (recorded and projected); such categories include UOG generation by technology type, power purchases and sales, CAISO market sales, and retail customer sales.
- Monthly volumes of Actual Sold, Retained, and Unsold RA.
- Monthly volumes of Actual Sold, Retained, and Unsold RPS.

With the advent of the PABA true-up, an even more detailed analysis of this type should also occur in the utility's annual ERRA Compliance Proceeding to understand how individual resources are performing in the market and whether there are systemic issues that can be addressed, either in the compilation of the PCIA forecast or in the actual optimization of the utility's resources. In the ERRA Compliance Proceeding a detailed review of individual procurement transactions, resource performance, and the drivers of the PABA balance should take place and any necessary adjustments to the actual results should be made.

As described above, PG&E should also provide in the ERRA Forecast application data to support the results on which it is relying to set rates. Without detailed data supporting the year-end PABA balance, including volumetric quantities underlying recorded costs and revenues, it is extremely difficult, if not impossible, to say whether PG&E's requested rate increase is reasonable, in particular given the significant variations from the previously forecasted amounts.

B. Actual Retained RPS Value Recorded to PABA Must Comply With the Commission's Order to Implement Last Year's ERRA Forecast Decision.

A key question in A.19-06-001 was what quantity of RPS generation should be classified as Actual Retained RPS, *i.e.*, the "volume used for IOU compliance." D.20-02-047 determined that the annual RPS compliance targets provided in D.11-12-020 are the "appropriate minimum quantity to be considered retained for purposes of the PABA true-up."[65] That is, the quantity of Actual Retained RPS each year must be equal to or greater than the annual RPS compliance target. The effect of the Commission's decision was to set the value of Retained RPS equal to PG&E's expected 2019 compliance target of 11,252 GWh, which eliminated all Unsold RPS for 2019.[66] The Commission ordered a corresponding adjustment to increase RPS value in the PABA by $92.9 million, which was the result of adjusting Retained RPS to the forecasted 2019 compliance target.

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65 D.20-02-047, p. 14 (February 27, 2020). It also determined that "the 20% of starting bank RECs…should not be counted as unsold RPS." *Id*., p. 16.

66 *Id*., pp. 13-16 (February 27, 2020).

PG&E's recorded PABA balance as of December 31, 2019, includes 4,213 GWh of Unsold RPS—the quantity proposed by PG&E in A.19-06-001 *prior* to the issuance of D.20-02-047—valued at $0. As recorded, Retained RPS is also less than the 2019 compliance target. Consequently, the beginning PABA balance used in this Application to determine the 2020 PABA under-collections is overstated by $92.9 million.

PG&E filed an Application for Rehearing ("**AFR**") of D.20-02-047 on March 30, 2020. Furthermore, rather than adjust the PABA balance to comply with D.20-02-047, PG&E recorded an adjustment of just $69.3 million to the PABA on March 31, 2020[67] based on its arguments made in the AFR. In PG&E's 2019 ERRA Compliance Application, A.20-02-009, PG&E filed Supplemental Testimony which included a discussion of D.20-02-047 and the impact on the PABA balance. PG&E's Supplemental Testimony reiterated the utility's disagreement with D.20-02-047 and asked the Commission to reconsider, as part of that case, the conclusions in D.20-02-047 and approve a PABA reduction of $69.3 million instead of $92.9 million.[68] Then, in its Rebuttal Testimony filed August 21, 2020, PG&E explained that as part of its August 2020 accounting close it would reverse the $69.3 million entry and record an adjustment of $92.9 million despite its disagreement with the amount.[69] A.20-02-009 is still pending before the Commission.

Through discovery and again in its August 2020 Supplemental Testimony PG&E disclosed that it "anticipates increasing the PABA RPS adjustment to $92.9 million as directed by the Commission in D.20-02-047…pending a Commission decision on

[67] *See* PG&E's response to Joint CCA DR 2.07.
[68] A.20-02-009, PG&E Supplemental Testimony, pp. 2-1 to 2-4 (Apr. 13, 2020).
[69] A.20-02-009, PG&E Rebuttal Testimony, p. 12-3 at lines 18-23 (Aug. 21, 2020).

PG&E's Application for Rehearing of D.20-02-047 or other Commission decision regarding this matter."[70] In testimony PG&E explained that the adjustment is not yet included in its Application, but will be included in the November Update of the year end balances of ERRA and PABA.[71] Correcting the 2020 PABA to conform RPS entries with D.20-02-047 will reduce the PCIA revenue requirement in this case by **$23.9 million**,[72] plus carrying charges that have been over-accrued since 2019.

V. ISSUES RELATED TO PG&E'S RATEMAKING PROPOSALS.

A. PG&E Proposes to Transfer Year-End ERRA Balances to PABA.

In its Prepared Testimony, PG&E proposes to credit a proportional share of the 2019 ERRA end-of-year balance to 2019 vintage departing load customers through a one-time PCIA rate adjustment for that vintage.[73] PG&E also proposes that the end-of-year ERRA balance going forward, "less the deferred revenue financed by bundled customers due to capped PCIA rate," be returned to the 2020 vintage and that this approach be standardized for future years.[74] PG&E explained the purpose of the transfer is to "ensure that the 2020 overcollected ERRA is returned to the Vintage 2020 non-exempt departing load customer and remaining bundled customers."[75]

PG&E's proposal is in direct response to issues raised by the Joint CCA's in PG&E's 2020 ERRA Forecast proceeding. In D.20-02-047, the Commission "agree[d] with the Joint CCAs that the net ERRA overcollection must be reflected in the PCIA

[70] *See* PG&E's response to Joint CCA DR 2.07.
[71] *See* PG&E Supplemental Testimony at 8:8-12.
[72] Including RF&U impact.
[73] Application at 5, 12-13, 18, 21; PG&E Prepared Testimony at 19-4:22-25.
[74] *See* PG&E Prepared Testimony at 19-7:6-15.
[75] *See id*. at 14-14:2-4.

rate," and that the "overcollection credit should benefit all customers who paid into the overcollection."[76] The Commission ordered PG&E to "include in its Energy Resource Recovery Account Forecast application for 2021 a method to properly credit vintage 2019 and 2020 departed load customers that does not have adverse effects on PCIA vintage subaccounts."[77]

After review of PG&E's testimony, workpapers, and responses to discovery, the Joint CCAs believe PG&E's proposals to credit the 2019 vintage for a portion of the ERRA balance and include the remaining year-end ERRA balance in the latest PABA vintage is reasonable given the current framework for establishing and tracking PCIA and ERRA rates and the Commission's directive to devise a solution with no 'adverse effects on PCIA vintage subaccounts.' As cited by PG&E, Southern California Edison ("**SCE**") made a similar proposal with regard to the year-end ERRA balance in its 2020 ERRA Forecast, which the Commission ultimately approved.[78] In its 2021 ERRA Forecast SCE has again proposed to transfer its year-end ERRA balance to the latest PABA vintage.[79]

The Joint CCAs note, however, that while the proposed ERRA treatment is generally reasonable under the current PCIA framework, it is complicated by the different timelines used to set PCIA rates and to determine a customer's vintage. That complication frustrates the ability of PG&E to meet the Commission's standard in D.20-02-047 that the "overcollection credit should benefit all customers who paid into the overcollection."[80] Because customer vintages are determined on a July to June schedule, PG&E's proposal

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[76] D.20-02-047, p. 11.
[77] *Id.*, Ordering Paragraph 4.
[78] D.20-01-022, p. 21
[79] A.20-07-004, Application of Southern California Edison Company for Approval of its Forecast 2021 ERRA Proceeding Revenue Requirement (July 1, 2020), Prepared Testimony at 121:15-18.
[80] D.20-02-047, p. 11.

to transfer year-end ERRA balances to the most recent vintage on a going-forward basis would ensure customers departing 'on or after July 1' are credited (or charged) for the ERRA balance accruing during the year of their departure.

However, the proposal does not include a similar credit (or debit) for customers that would depart PG&E's bundled service between January and June in future years. In response to Joint CCA DR 3.34, PG&E confirmed that customers departing between January and June 2020 would not be included in the 2020 year-end ERRA balance transfer but offered two explanations justifying the exclusion.[81]

First, customers receiving a share of the balance are those who departed on or after July 1, 2020 (or remain bundled PG&E customers) and who paid into ERRA for at least the first half of 2020.[82] That is, "half" of the vintage of affected customers will be made whole. The second reason is that, due to the mid-year customer vintage convention, if the ERRA balance is transferred to the 2019 vintage rather than the 2020 vintage, customers that depart between July 1, 2019 and December 31, 2019 would benefit from the transfer of the 2020 ERRA balance despite not having paid into ERRA during 2020.[83] Stated another way, PG&E's proposal would result in one group of customers not being made whole because doing so would unjustly benefit another group of customers.

To evaluate the potential impact on customers departing during the first half of 2020, the Joint CCAs developed an analysis similar to the approach proposed by PG&E to allocate a portion of the ERRA balance to the 2019 vintage. Specifically, the Joint CCAs requested PG&E provide the total 2020 bundled sales, i.e. usage while a bundled PG&E

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81 *See* PG&E's response to Joint CCA DR 3.34

82 *Id.*

83 *Id.*

customer, to customers that departed PG&E's service between January and June 2020.[84] At the time PG&E provided the actual sales data for these departing customers, only usage from January through May was available. Nonetheless, the bundled sales associated with customers departing during the first half of 2020 were divided by the total bundled sales forecast for 2020 to determine the portion of the projected 2020 ERRA balance that could be attributed to the departing load customers. Confidential Table 8 shows that the share of the 2020 ERRA balance attributed to customers departing between January and May 2020 is *de minimis*.

Confidential Table 8:
2020 ERRA Balance for January – May Departing Load

[redacted]

Thus, under PG&E's proposal, the overcollection credit will not benefit all customers who paid into the overcollection in 2020. However, that insufficiency amounts to unbundled customers departing between January and May 2020 missing out on less than $1 million total.

While PG&E's proposal provides a less-than-palatable approach to the issue raised by the Joint CCAs in the 2020 ERRA Forecast, the Joint CCAs acknowledge the complications raised by PG&E in response to Joint CCA DR 3.34. The current PCIA

84 *See* PG&E's response to Joint CCA DR 3.32

framework creates a quandary in that the different timelines used to set PCIA rates and to determine a customer's vintage mean some customers that overpaid their ERRA obligations cannot be made whole without benefitting other customers that did not pay the ERRA during the timeframe at issue.

As Table 8 shows, the impact on excluded customers during 2020 is minimal, but it is not clear the same will be always be true going forward. If the impact in future years becomes material, more nuanced solutions will be required. For this reason, PG&E's approach in this case should not be the approach used in future years in all circumstances. In addition, the Commission may want to consider changes to the PCIA framework overall to address this issue. One such potential change would be to align the time periods for determining a customer vintage and the period for setting PCIA and ERRA rates.

B. The Balance Owed to Bundled Customers for PUBA Financing Should be Treated the Same as the ERRA Balance.

The PCIA Financing Subaccount of PG&E's ERRA is used to track the amount financed by bundled customers related to the PUBA, that is, the revenue shortfall associated with capped PCIA rates for departing load customers. In its Prepared Testimony PG&E refers to the PCIA Financing Subaccount as a 'Revenue Deferral'[85] and projects the balance will reach \$286 million by the end of 2020.[86] Unlike other credits recorded to the ERRA, the PCIA Financing Subaccount Revenue Deferral does not represent an over-collection from bundled customers; rather, it represents the amount paid

85 *See* PG&E Prepared Testimony at 1-12:19-22.

86 *See* PG&E workpapers 14.ERRA 2021-Forecast_WP_PGE_202007001_Ch14_PUBLIC, tab 'One Time Adjustments.'

by bundled customers on behalf of departing load customers and which must be paid back to bundled customers. Due to this distinction, PG&E proposes to carve out "the deferred revenue financed by bundled customers due to capped PCIA rate"[87] from the ERRA balance and excludes it from the amount that is proposed to be transferred to the PABA. PG&E argues that the Revenue Deferral should not be transferred to PABA because it would be returned to bundled customers "upon the Commission authorization of a rate change in the [PUBA] Trigger Application."[88]

The Joint CCAs acknowledge the distinction between the Revenue Deferral in the PCIA Financing Subaccount and other entries to the ERRA. Nevertheless, the Revenue Deferral is functionally equivalent to an ERRA overcollection in that both represent a credit due to bundled customers. Returning an ERRA overcollection to bundled customers has the same effect as reimbursing bundled customers for having financed the PUBA – a reduction to future generation rates paid by bundled customers.

Because the return of the Revenue Deferral is functionally equivalent to returning an ERRA overcollection, it should be paid back in the same manner as an ERRA overcollection, *i.e.*, "reflected in the PCIA rate" to ensure any overcollection credit benefits "all customers who paid into the overcollection."[89] In particular, if the Revenue Deferral is effectuated only as a reduction to bundled rates, a customer who contributed to the Revenue Deferral prior to the PUBA Trigger Application but then leaves bundled service would no longer receive a credit, or refund, related to the Revenue Deferral. On the other hand, similar to the ERRA treatment, if the Revenue Deferral is transferred to the

[87] *See* PG&E Prepared Testimony at 19-7:6-15.
[88] *See* PG&E's response to Joint CCA DR 3.10.
[89] D.20-02-047, p. 11.

latest PABA vintage, customers would receive credit whether they remain bundled customers or choose to take unbundled service.

The Joint CCAs believe that it is not necessary or required to match the return of the Deferred Revenue with the recovery of the PUBA balance from departed load customers. The accumulation of the two balancing accounts is independent and based on the usage of the different customer groups. Treating the Deferred Revenue similar to an ERRA overcollection, and transferring the year-end balance to the latest PABA vintage in the annual ERRA Forecast Application, largely resolves the issue of ensuring the Deferred Revenue is returned to customers who contributed to its balance, even if they are no longer bundled PG&E customers. Indeed, when SCE created its version of the PCIA Financing Subaccount, it set up the Bundled Service Financing subaccount of the PUBA (rather than the ERRA) and established, "The year-end balance in this subaccount is returned, in its entirety with interest, through a transfer to the applicable vintage subaccount of the PABA."[90] PG&E should be required to follow the same approach.

C. PG&E Proposes to Include the Residual Year-End PUBA Balance in the 2021 PCIA Revenue Requirement.

As stated in the Application, the "PUBA was authorized in D. 18-10-019 to record the shortfall in revenues accruing from departing load customers when the PCIA cap is reached."[91] For each customer class and vintage, the per-kWh difference between the capped 2020 PCIA rate and the uncapped 2020 PCIA rate (what might be called the "PUBA Differential") is multiplied by actual departed customer usage each month in

90 SCE Advice 4084-E and SCE Preliminary Statement Section Q.3.b.
91 Application at 15.

2020. The resulting monthly accumulation of the PUBA Differential from all departed customers, plus interest, is tracked in the PUBA.

Once the cumulative amount in PUBA reaches 7% of PG&E's forecasted 2020 PCIA revenue from departed load customers, PG&E must, within 60 days, file an expedited trigger application that proposes "a revised PCIA rate that will bring the projected PUBA balance below 7% and maintain the balance below that level until January 1 of the following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect."[92] The purpose of that trigger filing will be to modify PCIA rates to recover the PUBA balance from unbundled customers. In its Prepared Testimony, PG&E projected the 2020 PUBA balance would reach $277.4 million, far exceeding the 7% trigger of $112.5 million.[93]

PG&E indicated in its Prepared Testimony that it anticipated filing a PUBA trigger application in 2020.[94] On September 21, 2020, PG&E filed its monthly ERRA Activity Report with the Commission, disclosing that the 7% trigger was exceeded in August 2020. The Joint CCAs do not yet know how PG&E will propose to recoup the PUBA balance from unbundled customers, but under any scenario, it is likely there will be a year-end PUBA balance in December 2020 that has not been disposed of by the expedited trigger application. Apparently in recognition of this, PG&E's Application requested "that any

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92 D.18-10-019, Ordering Paragraph 10.

93 The Joint CCAs Protest of PG&E's Application incorrectly quoted the 7% trigger as being $165.3 million which was shown in PG&E's ERRA Monthly Activity Report. Per Advice Letter 5781-E implementing D.20-02-047, "The 7 percent filing level is $112.5 million, and the 10 percent Trigger Threshold is $160.7 million."

94 *See* PG&E Prepared Testimony at 14-5:1 to 14-6:4.

year-end PUBA balance not disposed of via an expedited application process be included in the PCIA revenue requirement for recovery as part of its November Update."[95]

The question of what to do with the PUBA balance in terms of setting 2021 PCIA rates raises several important issues. First, PG&E requests the unamortized amount be included in the PCIA revenue requirement for recovery as part of its November Update. To accomplish this end, the utility suggests the creation of a vintage-specific PCIA rate adder to amortize the PUBA balance by vintage into PCIA rates.[96] This rate adder would be determined by dividing the forecasted year-end PUBA balance by vintage by the departing load billing determinants specific to each vintage.[97] The Joint CCAs find this approach reasonable because it appropriately maintains cost responsibility for PUBA balances within the vintages that accumulated the under-recovery.

The question then becomes whether the PCIA rate adder can "fit" under the capped PCIA rates. For 2021, PG&E projects the PABA revenue requirement—excluding any PUBA year-end balance—will result in capped rates for every vintage except 2020 and 2021, meaning there is no space below the rate caps with which to amortize year-end PUBA balances. As a result, "[d]ue to capped PCIA rates, the forecasted PUBA balance is not amortized into rates in this Application."[98] The Joint CCAs also find this approach reasonable, but note that while it adheres to the annual PCIA rate cap initially, it would result in the need for PG&E to file a PUBA trigger application soon, if not immediately,

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95 Application at 8.
96 *Id*. at 19-5:13-28.
97 *Id*. at 19-5:13-28.
98 *See* PG&E Prepared Testimony at 19-2:16-20, 19-4:19-21 and 19-5:32-33.

after the 2021 PCIA rate are effective.[99] This apparent conflict will need to be addressed in the resolution of PG&E's forthcoming PUBA trigger application. The Joint CCAs anticipate addressing the impact of the PUBA on 2021 PCIA rates once a clear proposal is received.

VI. ISSUES RELATED TO PG&E'S OTHER PROPOSALS.

A. PG&E Miscalculated the Resource Adequacy Component of GTSR and ECR Rates.

PG&E presents its calculation of its Green Tariff Shared Renewables, shown as E-GT, and Enhanced Community Renewables, shown as E-ECR, rates in Chapter 13 of its Prepared Testimony. One component of the E-GT and E-ECR rates is an RA charge, representing the RA Value for PG&E's bundled customers. However, PG&E makes an important error in calculating the RA charge for each of these rates.

In its Chapter 13 workpaper PG&E calculates 'RA Value – Bundled Customers' based on the market value of RA capacity, represented by the RA Adder used in the PCIA calculation.[100] The RA Adder is typically expressed in terms of kW capacity, so PG&E converts the $/kW-month value to a cents-per-kWh charge by applying the RA Adder to the net qualifying capacity of its PCIA-eligible generation resource portfolio and then dividing the total cost by annual retail load from bundled and unbundled customers. The cents-per-kWh rate is then included in the E-GT and E-ECR rates as the Resource Adequacy charge. PG&E's calculations result in a RA charge of 0.798 cents per kWh.

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99 *Id*. at Table 14-1 and pp. 19-15; PG&E Supplemental Response to Data Request 3.06. PG&E projects a $277.4 million year-end PUBA balance and a 7% PUBA trigger filing level of $127.2 million.

100 13.ERRA 2021 Forecast_WP_PGE_20200701_Ch13_CONF.xlsx, sheet "RA Adder".

PG&E's calculation of the RA cost per kWh of customer load does not properly match the RA capacity with the customer load it serves. PG&E's generation resource portfolio is intended to serve its bundled customers, and PG&E recognizes Retained RA for bundled customers in the PCIA calculation. While it is generally true that PG&E owns or controls more capacity than it needs to meet its obligation for bundled customers, its portfolio alone does not represent all of the resource capacity used to meet RA requirements for bundled *and* unbundled customers. Dividing the value of PG&E's RA capacity by the total sales to bundled *and* unbundled customers inflates the billing determinants in the denominator and understates the cost of RA on a per-kWh basis. This mismatch of cost responsibility and corresponding load underestimates the RA cost component by nearly 40%.

To correct the mismatch between cost and load, PG&E should modify its calculation of the RA charge in two ways. First, the RA capacity of PG&E's resource portfolio should reflect only Retained RA to serve bundled load as reported in PG&E's Chapter 9 workpapers used to calculate the PCIA. Second, customer load used to convert the RA costs to a volumetric charge should reflect only PG&E's bundled load. Adjusting the numerator and denominator to reflect the costs and load for only bundled customers properly matches PG&E's costs and load. Correcting PG&E's calculation increases the Resource Adequacy charge for E-GT and E-ECR from $0.00798/kWh to $0.01312/kWh.

B. PG&E Must Ensure Energy Supply Administration Costs Are Not Double Counted in the PCIA and the CAM.

PG&E filed Supplemental Testimony on August 14, 2020, to address, in part, the Commission's decision (D.20-06-002) requiring submission of administrative costs forecasted to be incurred by PG&E serving in its new role as the central procurement entity ("**CPE**") for local RA in its distribution service area. In its testimony PG&E describes that it intends to establish the CPE as a department within PG&E that will "function similarly to existing departments within PG&E that employ separation practices designed to promote competitive neutrality and perform walled-off functions."[101] It also explains that it "anticipates that the CPE will utilize some existing functions within the broader utility to promote efficiency"[102] and to "allow the CPE to leverage existing PG&E resources, knowledge, and experience."[103]

PG&E provided a forecast of CPE administrative costs, totaling $16.5 million for 2021, in Table 6-2 of its Supplemental Testimony. PG&E did not clearly articulate, however, whether the $16.5 million represents costs solely for newly-added resources or systems or if it also includes the estimate of costs incurred by relying on existing PG&E personnel or other resources. PG&E should be required to quantify the CPE-related costs expected to be incurred by strictly incremental resources versus existing personnel or other resources at PG&E.

Notably, existing costs related to PG&E's ESA department resources are already allocated for recovery between the PCIA, ERRA, and CAM accounts. This allocation is done based on the Common Cost allocation factor from PG&E's last general rate case, which did not take into account the creation of a new CPE department or the sharing of existing resources with the CPE. If existing ESA resources will be shared with the CPE in the future, a greater portion of those costs must be allocated to the CAM (a.k.a. NSGBA) which would reduce the allocation to the PCIA. PG&E should be required to

101 *See* PG&E Supplemental Testimony at 2:20-22.
102 *Id.* at 2: 24-25.
103 *Id.* at 3:8-12.

explain whether any existing ESA costs will be shared with the CPE in 2021 and adjust the assignment of ESA costs among PCIA, ERRA, and CAM accounts accordingly.

C. PG&E Should Include Funding for CCAs' Offerings of Low-Income and Disadvantaged Community Solar Programs in its 2021 Budget Proposal, Funded in Whole or in Part from GHG Allowance Revenues.

Chapter 17, Section C, of Prepared Testimony describes PG&E's proposed funding for its low-income and disadvantaged community solar programs that were authorized in Decisions 17-12-022 and 18-06-027. Those programs are to be funded initially from the state's greenhouse gas (**"GHG"**) allowance auction proceeds fund, up to the total allocated by the Commission decisions, with the residual amount to come from Public Purpose Program ("**PPP**") funds.[104]

CCAs also were authorized to offer disadvantaged community green tariff ("**DAC-GT**") and community solar green tariff ("**CS-GT**") programs that draw from the same funding sources:[105]

> *(W)e find that it is reasonable to use a portion of the proceeds from the sale of GHG allowances as the primary funding source for both the DAC-SASH and DAC-Green Tariff programs. As MCE notes, GHG auction proceeds are intended to benefit both bundled and unbundled customers. Consistent with this, it is reasonable for CCA customers to be eligible for a comparable CCA DAC-Green Tariff.* [106]

Resolution E-4999 confirms this understanding.[107] Specifically, Resolution E-4999 reserved capacity for CCAs based on the proportionate share of service area

[104] *See* PG&E Prepared Testimony at 17-5.
[105] *See* D.18-06-027 at page 4 and pages 55-56.
[106] *See* D.18-06-027 at page 55.
[107] *See* Res. E-4999, at pages 5-6.

residential population,[108] and allows CCAs to share and trade these allocations to make the programs financially more feasible.[109] Two CCAs, MCE and EBCE, have now filed advice letters to establish and implement their respective DAC-GT and CS-GT programs.[110] Three other CCAs are currently planning to file advice letters by November 2020[111] and others may do so by January 1, 2021.

The question yet to be addressed by the Commission, raised in part by PG&E's inclusion of these programs in this ERRA Application, is how the Commission will allocate the GHG Allowance and PPP Funds to the CCAs administering their own programs. PG&E includes its budget for its four low-income and disadvantaged community programs in its revenue requirement request,[112] but it does not include the budget for the CCAs' programs.

The Joint CCAs' program budgets should be determined concurrently with that of PG&E since all budgets draw from the same pool of GHG revenues. For this reason, the Joint CCAs request that PG&E include in its November Update the funding for eligible CCA programs for which the requisite advice letters have been filed. Advice letters for MCE and EBCE include program budgets of $1,992,897 and $984,922, respectively. PG&E's updated request should include the program budgets for all LSEs that have submitted such budgets to the Commission for approval via the Advice Letter process by

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[108] *See* Res. E-4999, at pages 12-14.

[109] *See* Res. E-4999, at page 16.

[110] MCE, Advice Letter 42-E, May 7, 2020 (including budget of $1,992,897 in Appendix C); EBCE, Advice Letter 14-E, September 11, 2020 (including budget of $984,921.53 in Appendix C).

[111] Peninsula Clean Energy, San Jose Clean Energy, and Silicon Valley Clean Energy.

[112] PG&E Prepared Testimony at pages 17-12-17-13. The GHG Allowance Revenue Return comes from the California Air Resources Board's Statewide Cap and Trade Program Allowance Auction and the Public Purpose Program rate components are determined in PG&E's General Rate Case

the time the November Update is filed, with a specification of how the funding sources are allocated across those programs.

This concludes my testimony.

Attachment A – Brian Dickman CV

NewGen Strategies & Solutions

Brian Dickman
Executive Consultant
bdickman@newgenstrategies.net

Mr. Brian Dickman is an Executive Consultant in NewGen's energy practice with over 18 years of experience in the utility industry, with a focus on regulatory analytics. He has extensive experience preparing and evaluating utility revenue requirement and cost allocation studies, developing utility avoided costs, and evaluating the impact of new initiatives and transactions on a utility and its customers. Mr. Dickman's work has also included regulatory and financial modeling support for potential mergers and acquisitions, variable production cost simulations, valuations of potential asset acquisitions and other commercial opportunities, and pricing for Qualifying Facilities under the Public Utility Regulatory Policies Act. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process and he has personally testified as an expert witness before the public utility commissions of California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming. Mr. Dickman has led utility regulatory teams in the development of cost recovery filings in multiple state jurisdictions and the Federal Energy Regulatory Commission.

EDUCATION

- Master of Business Administration, Finance Emphasis, University of Utah
- Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

- Revenue Requirement
- Cost of Service
- Regulatory Environment
- Financial Analysis and Modeling

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads project teams in the establishment of utility revenue requirements, evaluation of cost of service studies and retail and wholesale rates, and other regulatory analyses for numerous electric utilities. Previously, Mr. Dickman led departments at a multi-billion-dollar utility responsible for interfacing with six state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, and financial impacts of utility initiatives. He now works with clients and stakeholders to prepare and evaluate cost of service studies and rate design proposals, and to help clients understand the regulatory environment impacting policy objectives. Mr. Dickman’s experience also includes evaluating the rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load.

A sample of Mr. Dickman’s regulatory analysis clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Austin Energy, Texas
- East Bay Community Energy, California
- Los Angeles Department of Water and Power, California
- Lubbock Power and Light, Texas
- Monterey Bay Community Power, California
- New York Power Authority, New York
- Blackstone Group, New York
- Duke Energy, North Carolina
- Facebook, Inc., California
- Hemlock Semiconductor, Michigan
- Hydro One, Ontario CA
- Liberty Utilities, California
- Minnesota Power, Minnesota
- Newmont Mining, Nevada

- New York State Energy Research & Development, New York
- Transmission Agency of Northern California, California
- Tri-County Metropolitan Transportation District, Oregon
- Portland General Electric, Oregon
- SABIC Innovative Plastics Mt. Vernon, LLC
- Vermont Gas Systems, Vermont
- Vistra Energy, Texas

Expert Witness and Litigation Support

Mr. Dickman offers expert testimony regarding cost of service, rate design, and ratemaking issues before state and local regulatory bodies. He has experience providing litigation support regarding ratemaking matters at wholesale and retail levels in California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board.

Mr. Dickman has provided comprehensive expert testimony related to system revenue requirements, cost allocation, variable production costs, generation avoided costs, and resource valuation. Mr. Dickman's expert witness and litigation support includes:

Revenue Requirement/Cost Allocation

Mr. Dickman has prepared and evaluated revenue requirement, inter-jurisdictional cost allocation, and coincident peak allocation studies, supporting testimony for PacifiCorp and other clients in the following dockets:

- Wyoming Docket No. 20000-405-ER-11
- Wyoming Docket No. 20000-384-ER-10
- Wyoming Docket No. 20000-352-ER-09
- Wyoming Docket No. 20000-333-ER-08
- Utah Docket No. 10-035-89
- Idaho Case No. PAC-E-08-07
- Idaho Case No. PAC-E-06-10
- FERC Docket No. ER16-2320
- FERC Docket No. ER17-2154
- FERC Docket No. ER19-231-002
- FERC Docket No. ER20-270-000
- OEB Case No. EB-2018-0270
- Indiana Cause No. 43354 MCRA 21 S1

Power Supply Cost Modeling and Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing load. These cases include the following:

- Oregon Docket UM 1662
- Oregon Docket UE 287
- Oregon Docket UE 296
- Oregon Docket UE 307
- Oregon Docket UE 375
- Wyoming Docket No. 20000-389-EP-11
- Wyoming Docket No. 20000-447-EA-14
- Wyoming Docket No. 20000-469-ER-15
- Utah Docket No. 12-035-67
- Utah Docket No. 13-035-32
- Utah Docket No. 14-035-31
- Utah Docket No. 15-035-03
- Idaho Case No. PAC-E-13-03
- Idaho Case No. PAC-E-14-01
- California Docket A.12-08-003
- California Docket A.13-08-001
- California Docket A.14-08-002
- California Docket A.19-06-001
- California Docket A.18-06-001
- California Docket A.20-02-009

Avoided Costs/Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components to be included in a proposed method for valuing solar generation resources, calculation of PURPA avoided costs for large resources, and support of modifications to the avoided cost calculation for small resources. These cases include the following:

- Oregon Docket UM 1610
- Oregon Docket UM 1716
- Wyoming Docket No. 20000-481-EA-15
- Utah Docket No. 15-035-T06
- Washington Docket UE-144160
- Idaho Case No. GNR-E-11-03
- Idaho Case No. PAC-E-15-03

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries

- *Customer Choice at a Vertically Integrated Utility*

Record of Testimony Submitted by Brian Dickman

Client	Utility	Proceeding	Subject	Before	Year
1. Clean Power Alliance of Southern California	Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	2020
2. Facebook, Inc.	Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	2020
3. Joint Community Choice Aggregators	Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	2020
4. SABIC Innovative Plastics Mt. Vernon, LLC	Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	2020
5.	PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	2016
6.	PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon	2015
7.	PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	2015
8.	PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming	2015
9.	PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah	2015
10.	PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon	2015
11.	PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming	2015

Record of Testimony Submitted by Brian Dickman

Client	Utility	Proceeding	Subject	Before	Year
12.	PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah	2015
13.	PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission	2015
14.	PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission	2014
15.	PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	2014
16.	PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission	2014
17.	PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission	2014
18.	PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming	2014
19.	PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah	2014
20.	PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission	2013
21.	PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission	2013
22.	PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah	2013

Record of Testimony Submitted by Brian Dickman

Client	Utility	Proceeding	Subject	Before	Year
23.	PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon	2012
24.	PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission	2012
25.	PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah	2012
26.	PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming	2011
27.	PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming	2011
28.	PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission	2011
29.	PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low income customer weatherization rebates	Idaho Public Utilities Commission	2010
30.	PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming	2010
31.	PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah	2010
32.	PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming	2009
33.	PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission	2008

Record of Testimony Submitted by Brian Dickman

Client	Utility	Proceeding	Subject	Before	Year
34.	PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming	2008

Attachment B – Selected DR Responses

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA_002-Q07		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_002-Q07		
Request Date:	July 20, 2020	Requester DR No.:	002
Date Sent:	August 3, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Ryan Stanley/Angelia Vega	Requester:	Tim Lindl

QUESTION 07

Referring to PG&E's Prepared Testimony at Table 14-2 and p. 14-12: Please confirm the 2020 forecast year-end PABA balance reflects only a $69.3 million adjustment instead of the $92.9 million RPS adjustment authorized in D.20-02-047? Please provide supporting documentation verifying the date and amount of the PABA adjustment. If not confirmed, please explain why not.

ANSWER 07

Yes, PG&E forecast year-end PABA balance in the Prepared Testimony includes a $69.3 million RPS adjustment. The $69.3 million RPS adjustment was recorded in the March accounting close as reflected below. The $69.3 million accounting entry was made to reverse the 2019 unsold RPS amount recorded in 2019.

Display Document: Data Entry View

Taxes Display Currency General Ledger View

Data Entry View

Document Number	1002560626	Company Code	PGE1	Fiscal Year	2020
Document Date	03/31/2020	Posting Date	03/31/2020	Period	3
Reference	NR	Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment	Ref. Key 1
1	40	1823051	BA - ERRA				69,261,720.00	RPS Adj	T01
2	50	4000907	ERRA Revenue - Elec			14759	69,261,720.00-	Unsold RPS	T01
3	40	4000868	PABA Revenue - Elec			15927	69,261,720.00	Unsold RPS	T03
4	50	1823252	BA - PABA				69,261,720.00-	RPS Adj	T03
5	50	1823252	BA - PABA				266,822.73-	Interest	T06
6	40	4103032	Interest Income- BA			10612	266,822.73	Interest	T06
7	40	1823051	BA - ERRA				266,822.73	Interest	T07
8	50	5052002	Interest Expense- BA			10612	266,822.73-	Interest	T07

PG&E anticipates recording a subsequent adjustment of $24 million to increase the unsold RPS adjustment to $92.9 million as directed by the Commission in Decision 20-02-047. PG&E expects to maintain this adjustment pending a Commission decision on PG&E's Application for Rehearing of D.20-02-047 or other Commission decision regarding this matter.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA_002-Q13		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_002-Q13		
Request Date:	July 20, 2020	Requester DR No.:	002
Date Sent:	August 3, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Angelia Vega	Requester:	Tim Lindl

QUESTION 13

Referring to PG&E's Prepared Testimony at page 18-2 lines 1 - 5:

(a) Please identify all regulatory proceedings affecting the $2,522.5 million of UOG related costs.

(b) Please specify whether the costs from each proceeding included in PG&Es 2021 ERRA filing are commission approved or pending approval.

(c) Please provide citations within the specific regulatory proceedings in which the total UOG related costs of $2,522.5 million costs can be found.

ANSWER 13

Regarding subpart (a), the regulatory proceedings affecting the $2,522.5 million, including revenue franchise fee and uncollectibles (RF&U) are listed as follows:

Line No.		$'000
1	2020 General Rate Case (GRC)	2,283,000
2	Cost of Capital	5,770
3	Pension	49,484
4	Diablo Canyon Reirement Cost	53,217
5	Wildfire Expense Memorandum Account	131,092
6	PG&E Moss Landing Energy Storage	31,254
7	Subtotal	$2,553,817
8	Less: Adjustments*	(31,326)
9	Total	$2,522,491

* Adjustments for anticipated hydro sales and other allocated amounts not included in this application for recovery

Regarding subparts (b) and (c), PG&E responds as follows:

1. 2020 GRC -- Based on PG&E's settlement agreement in its 2020 General Rate Case (GRC) Application (A.) 18-12-009 that is currently pending before the Commission. The $2,283 million is extracted from Appendix C, Line 9, Column B, "2021 Proposed".
2. Cost of Capital -- Ordering Paragraph (OP) 2 of Decision (D.)19-12-056 adopted a set of Cost of Capital Structure for PG&E's test year 2020 operation. The amount of $5.77 million included in the July testimony is a placeholder based on the amount included in the "Adopted Rolling Revenue Requirements Report from 2017 GRC through 2019" shown in Advice 4196-G/5720-E as Attachment 1. Advice 4196-G/5720-E was authorized by the Commission on February 21, 2020, effective as of January 1, 2020.
3. Pension -- D.09-09-020 adopted a methodology of Pension calculation, including any regulatory procedures regarding updating the Pension amounts. The amount of $49.484 million included in the July testimony is authorized by the Commission in Advice 4196-G/5720-E on February 21, 2020, effective as of January 1, 2020.
4. Diablo Canyon Retirement Cost -- D.18-01-022 adopted a certain funding of the Employee Retention Program to ensure qualified employees were retained at Diablo Canyon Power Plant up to closure of Units 1 and 2 in 2024 and 2025. The amount of $53.217 million (including currently effective RF&U of 0.011349) in the July testimony is based on that authorized by the Commission in Advice 5461-E-A. Advice 5461-E-A was authorized by the Commission on February 8, 2019, effective as of January 1, 2020.
5. Wildfire Expense Memorandum Account -- The Wildfire Expense Memorandum Account (WEMA) amount of $131.092 million can be found on Table 3-5 on page 3-9 of the testimony. It includes recorded insurance cost that PG&E is requesting for recovery in its WEMA Application (A.) 02-02-004. This application is currently pending before the Commission.
6. PG&E Moss Landing Energy Storage -- Resolution (Res.) E-4949, issued November 9, 2018, approved CAM treatment for certain energy storage projects, including PG&E's Utility-Owned Generation (UOG) Moss Landing Energy Storage facility. The UOG revenue requirement for Moss Landing is based on that contained in Advice Letter 5322-E, approved in Res. E-4949.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Supplemental Data Response

PG&E Data Request No.:	Joint-CCA_003-Q06		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_003-Q06Supp01		
Request Date:	July 31, 2020	Requester DR No.:	003
Date Sent:	August 26, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Angelia Vega/ Ben Kolnowski	Requester:	Tim Lindl Julia Kantor Alicia Zagola Brian Dickman Richard McCann

QUESTION 06

Referring to PG&E Prepared Testimony at Table14-1, pp.19-5 to 19-6, and p. 19-15, PG&E projects a $277.4M year-end PUBA balance and a 7% PUBA trigger filing level of $127.2M. Is it PG&E's opinion that if none of the $277.4M year-end PUBA balance is amortized prior to the end of this proceeding (i.e., neither the anticipated PUBA trigger proceeding nor the capped rates adopted in this case end up reducing the year-end balance), PG&E would meet the PUBA trigger threshold immediately after 2021 PCIA rates are effective?

ANSWER 06_SUPP

In the scenario as described in the question, it is clear that the $277.4M would have already exceeded the 7% PUBA trigger filing level upon implementation of 2021 PCIA rates.

PG&E's requested treatment of the PUBA balance is described on pages 18-2 and 18-3 of the Opening Testimony filed on July 1, 2020.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA 003-Q10		
PG&E File Name:	ERRA-2021-PGE-Forecast DR Joint-CCA 003-Q10		
Request Date:	July 31, 2020	Requester DR No.:	003
Date Sent:	August 14, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Angelia Vega	Requester:	Tim Lindl

QUESTION 10

Referring to PG&E's Prepared Testimony at page 1-12 lines 25-27: Please explain why the Revenue Deferral is treated different from the ERRA overcollection in that PG&E proposes to not transfer the year end Revenue Deferral balance to the PABA but rather to keep it in ERRA.

ANSWER 10

The Revenue Deferral in ERRA is the amount that PG&E expects to record in the PCIA Financing Subaccount (PFS) as described in PG&E's electric Preliminary Statement Part CP as follows:

6. PCIA FINANCING SUBACCOUNT

   The purpose of the PCIA Financing Subaccount is to track the amount financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers.

The Revenue Deferral is recorded to the PFS in ERRA as a credit and it is not an over-collected ERRA balance. It is generation revenue financed by PG&E's bundled customers to the benefit of departing load customers resulting from capped PCIA rates. Or, in other words, the amounts in the PFS are simply accounting entries tracking amounts owed by one set of customers to another. Therefore, the Revenue Deferral should not be transferred to PABA because it would be returned to bundled customers and reduced accordingly upon the Commission authorization of a rate change in the PCIA Undercollection Balancing Account (PUBA) Trigger Application.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA 003-Q14		
PG&E File Name:	ERRA-2021-PGE-Forecast DR Joint-CCA 003-Q14		
Request Date:	July 31, 2020	Requester DR No.:	003
Date Sent:	August 14, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Angelia Vega/George Clavier	Requester:	Tim Lindl

QUESTION 14

Referring to PG&E Workpaper 09.ERRA_2021 Forecast_WP_PGE_20200701_Ch09_CONF.xlsx, tab 'CONF CAL Table 9-1': Please reconcile the Unsold RA quantities shown on Line Nos. 4.3, 5.3, and 6.3 with PG&E's Prepared Testimony at page 9-4, footnote 13, which states "PG&E forecasts that 10 percent of available surplus capacity will remain unsold."

ANSWER 14

PG&E's August Supplemental includes a correction to Footnote 13 on page 9-4 of PG&E's Prepared Testimony, which reads as:

"For the purposes of the July 1 forecast, placeholder values of zero were used in the PCIA benchmark calculation; these values will be revised in the November forecast when there will be a more complete accounting of the number and magnitude of RA sales executed in 2020 for 2021."

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA 003-Q32		
PG&E File Name:	ERRA-2021-PGE-Forecast DR Joint-CCA 003-Q32		
Request Date:	July 31, 2020	Requester DR No.:	003
Date Sent:	August 14, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Ben Kolnowski	Requester:	Tim Lindl

QUESTION 32

Referring to PG&E's Prepared Testimony page 19-7 lines 23-28: Please quantify the bundled sales volume, by rate group, from January through June 2020 associated with customers who departed PG&E service between January 1 and June 30, 2020.

ANSWER 32

At the time of drafting this response, PG&E can only provide recorded sales volumes by rate group from January 1, 2020 through May 30, 2020. The bundled sales volumes presented in the table below are for customers who have departed from January 1, 2020 through May 30, 2020.

Bundled electric sales for the period January 1, 2020 - May 30, 2020 to customers that departed PG&E's bundled service from January 1, 2020 - May 30, 2020

Customer Class	Electric Sales (kWh)[1]
Residential	29,947,863
Small Commercial	4,247,452
Medium Commercial	23,881,542
Streetlights	-
Standby	-
Agriculture	6,706,676
Large Commercial & Industrial	9,683,123
Total	74,466,655

[1]Data is from PG&E's Rate Data Analytics' Normalized Billing datasets. Reflects updates to recorded billing information due to rebills, rebates, and other billing irregularities, and may not match other sources of published sales data.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA_003-Q34		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_003-Q34		
Request Date:	July 31, 2020	Requester DR No.:	003
Date Sent:	August 14, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power
PG&E Witness:	Ben Kolnowski	Requester:	Tim Lindl

QUESTION 34

Referring to PG&E's Prepared Testimony page 19-9 lines 21-24: Please confirm that customers departing between January 1 and June 30, 2020 would not receive credit through the adjusted PCIA rates related to their contribution to the ERRA overcollection accrued during 2020.

ANSWER 34

Confirmed. PG&E has constructed its proposal for the year-end ERRA balance to follow a standard ratemaking approach which leverages the existing PCIA rate design process. By transferring the year-end ERRA balance to the most recent vintage subaccount in PABA, the balance is amortized to vintage 2020 and 2021 customers through cumulative PCIA rate design. Through this process, the year-end balance is effectively divided by the applicable billing determinants to determine the incremental system average PCIA rate. This rate is then applied to both vintage 2020 and vintage 2021 PCIA rates through cumulative PCIA rate design. By transferring the balance to the 2020 subaccount in PABA, customers who depart on or after July 1, 2020, and have paid into ERRA for at least the first half of 2020, would receive a share of the balance.

This approach results in the 2019 vintage, which includes customers who depart bundled service between July 1, 2019 and June 30, 2020, not being impacted by this transfer. If PG&E instead transferred the forecasted 2020 year-end ERRA balance to the vintage 2019 subaccount in PABA, customers that depart between July 1, 2019 and December 31, 2019, which have not paid into ERRA at all during the year 2020, would be impacted by the transfer. In addition, the 2019 vintage would receive the same rate impact as the more recent vintages, even though only a subset of customers in the 2019 vintage had contributed to ERRA for only a short period in 2020.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA_004-Q01		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_004-Q01		
Request Date:	August 21, 2020	Requester DR No.:	004
Date Sent:	September 04, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power/ Valley Clean Energy Alliance
PG&E Witness:	Ryan Stanley	Requester:	Tim Lindl

QUESTION 01

Referring to JCCA DR 2.3: Please provide Excel versions of confidential monthly reports. Please consider this an ongoing request.

ANSWER 01

PG&E objects to the level of detail requested in this JCCA DR 2.3 because the issues it raises are outside the scope of this proceeding. The detailed review of recorded entries in ERRA-related balancing accounts is performed in connection with the ERRA Compliance Review proceeding.

Subject to and notwithstanding this objection, PG&E is providing a confidential excel copy of the ERRA Activity Report submitted in compliance with Decision 02-12- 074, Ordering Paragraph 19, for the month of July 2020. The excel version of the ERRA Activity Report for July 2020 includes year-to-date-prior period adjustments for the ERRA, PABA, and PUBA accounts, as well as vintage views of PABA and PUBA. Please see the following attachment:

- Attachment 1: July 2020 Confidential ERRA Activity Report (see filename, “ERRA-2021-PGE-Forecast_DR_Joint-CCA_002_Q03Atch07-CONF.xlsx”).

Attachment is confidential.

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2021 Forecast
Application 20-07-002
Data Response

PG&E Data Request No.:	Joint-CCA_004-Q11-CONF11		
PG&E File Name:	ERRA-2021-PGE-Forecast_DR_Joint-CCA_004-Q11-CONF		
Request Date:	August 21, 2020	Requester DR No.:	004
Date Sent:	September 04, 2020	Requesting Party:	East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy/ Pioneer Community Energy/ San Jose Clean Energy Silicon Valley Clean Energy/ Sonoma Clean Power/ Valley Clean Energy Alliance
PG&E Witness:	Angelia Vega/George Clavier	Requester:	Tim Lindl

QUESTION 11

Referring to workpaper “09.ERRA_2021 Forecast_WP_PGE_20200701_Ch09_CONF.xlsx” tab ‘CONF CTC and PCIA’: For the RA Contracts (LogNumbers: 33B229P01, 33B117S01, 33B217S01, 33B217T01, 33B217T02, 33B235S02):

a. Please confirm that the data on the referenced tab reflect the costs of the contracts but no MW capacity (i.e. 0 NQC in columns E – G).
b. Please explain whether the referenced RA contracts contribute capacity that is used to meet PG&E’s RA obligation for bundled customers.
c. If the answer to part b above is affirmative, please explain why no RA capacity from the contracts is included in the PCIA as Retained RA.
d. If the answer to part b above is negative, please explain the purpose of the RA contracts and why the costs are included in the PCIA.

ANSWER 11

The response to this data response contains Confidential Information subject to the Nondisclosure Agreement between PG&E and Tim Lindl, Alicia Zaloga, Brian Dickman, and Richard McCann

a) PG&E confirms that the the data on the referenced tab reflect the costs of the contracts but no MW capacity (i.e. 0 NQC in columns E – G).

b) PG&E confirms that the referenced RA contracts contribute capacity that is used to meet PG&E’s RA obligation for bundled customers.

c-d) The MW capacity of these contracts that were inadvertently omitted in the workpaper ““09.ERRA_2021 Forecast_WP_PGE_20200701_Ch09_CONF.xlsx” tab ‘CONF CTC and PCIA’ and the associated Retained RA value that would have reduced the PCIA revenue requirement, with corresponding increase in ERRA revenue requirement is as follows:

LogNumbers	RA Type	Avg MW	Market Price Benchmark authorized in D.20-02-047 $/kW-year	Retained RA Value ($)
33B229P01	Local	[redacted]	$49.32	[redacted]
33B117S01	Local		$49.32	
33B217S01	Local		$49.32	
33B217T01	Local		$49.32	
33B217T02	Local		$49.32	
33B235S02	Local		$49.32	
			Total	

The values reflected in the above table will be updated in the November Update of this proceeding.

Attachment C – RA Market Report

LR1/nd3 1/14/2020

FILED
01/14/20
11:35 AM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020

ASSIGNED COMMISSIONER'S RULING ON ENERGY DIVISION'S RESOURCE ADEQUACY STATE OF THE MARKET REPORT

Summary

This Assigned Commissioner's Ruling attaches the Commission's Energy Division's State of the Market Resource Adequacy Report, as directed by Decision (D.) 19-02-022.

1. Background

In D.19-02-022, the Commission recognized that it is of critical importance that parties to the Resource Adequacy (RA) proceeding have reasonable insight about the current and future state of the RA market. The Commission recognized that certain information regarding the broader RA procurement outlook is not publicly available and only visible to Energy Division Staff. Therefore, in order to increase transparency into the state of the RA market, D.19-02-022 directed Energy Division Staff to prepare two reports that address the following:

(1) Total MW for any/all resources procured (gas, storage, renewable/DER) to meet RA requirements;

(2) Development of preferred resources in local and system areas;

(3) Information regarding local deficiencies, including the number of load service entities (LSEs) that are deficient, type of LSE (IOU, CCA, ESP), location of deficiencies, amount of deficiencies (in MW), number of local RA waiver requests, and anonymized statements from the LSE as to the reason for the deficiency (such as which generators bid into the solicitation, whether the bids included dispatch rights or other terms addressing how local resources bid in the energy market);

(4) Information regarding system and flexible capacity deficiencies, including anonymized statements from the LSE as to the reason for the deficiency; and

(5) Resources on the Net Qualifying Capacity list that are not shown in RA filings as under contract to an LSE(s).[1]

The Commission further directed that "Energy Division's first report shall be submitted within 60 days of the decision setting the year-ahead RA requirements. The second report shall be issued by Energy Division within 60 days of the October 31, 2019 filings for the 2020-2022 RA compliance years."[2]

2. RA State of the Market Report

Energy Division's second Resource Adequacy State of the Market report is hereby attached to this ruling as Appendix A.

IT IS RULED that Energy Division's second Resource Adequacy State of the Market report is attached to this ruling as Appendix A.

Dated January 14, 2020, at San Francisco, California.

/s/ LIANE M. RANDOLPH
Liane M. Randolph
Assigned Commissioner

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[1] D.19-02-022 at 32.

[2] *Id*. at 48, Ordering Paragraph 17.

APPENDIX A

THE STATE OF THE RESOURCE ADEQUACY MARKET - REVISED

January 13, 2019

October-December 2019 Month Ahead & 2020 Year Ahead Filing Information

CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/RA/

Report Authors:
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Michele Kito, Supervisor, Resource Adequacy and Procurement Oversight
Judith Iklé, Program Manager, Procurement Strategy and Oversight

TABLE OF CONTENTS

TABLES

LIST OF ACRONYMS

CAISO	California Independent System Operator	LSE	Load Serving Entity
CAM	Cost Allocation Mechanism	MA	Month Ahead
CCA	Community Choice Aggregator	MIC	Maximum Import Capability
CHP	Combined Heat and Power	MW	Megawatt
CPUC	California Public Utilities Commission	NQC	Net Qualifying Capacity
DER	Distributed Energy Resource	PG&E	Pacific Gas & Electric
DR	Demand Response	PRM	Planning Reserve Margin
DRAM	Demand Response Auction Mechanism	RA	Resource Adequacy
ELCC	Effective Load Carrying Capability	RFO	Request for Offers
ESP	Electric Service Provider	RMR	Reliability Must Run
IOU	Investor Owned Utility	SCE	Southern California Edison
IV	Imperial Valley	SDG&E	San Diego Gas & Electric
LA	Los Angeles	TAC	Transmission Access Charge
LCR	Local Capacity Requirement	YA	Year Ahead

1. INTRODUCTION

California Public Utilities Commission (CPUC) Decision 19-02-022 directed Energy Division staff to prepare two reports that would provide "reasonable insight about the current and future state of the Resource Adequacy (RA) market"[1] in order to assist parties as they developed proposals for a central buyer of local RA.

The decision outlines five elements that the reports must address:

1. Total Megawatts (MW) for any/all resources procured – (gas, storage, renewable)/distributed energy resource (DER)) – to meet RA requirements;
2. Development of preferred resources in local and system areas;
3. Information regarding local deficiencies, including the:
    a. number of load serving entities (LSEs) that are deficient,
    b. type of LSE (investor owned utility (IOU), community choice aggregator (CCA), electric service provider (ESP)),
    c. location and amount of deficiencies (in MW),
    d. number of local RA waiver requests, and anonymized statements from the LSE as to the reason for the deficiency (such as which generators bid into the solicitation, whether the bids included dispatch rights or other terms addressing how local resources bid in the energy market);
4. Information regarding system and flexible capacity deficiencies, including anonymized statements from the LSE as to the reason for the deficiency; and
5. Resources on the Net Qualifying Capacity list that are not shown in RA filings as under contract to an LSE(s).[2]

The initial State of the Market Report, issued September 3, 2019, covered RA filings from the 2019 year ahead filing through the September month ahead filing. This revised report adds data from the remainder of the 2019 month ahead filings and the 2020 year ahead filing.

[1] D.19-02-022 at 31.

[2] D.19-02-022 at 31-32.

2. RESOURCES PROCURED FOR RA-2019 MONTH AHEAD FILINGS

This section is largely the same as Section 2 of the initial State of the Market Report. The main difference here is that Tables 1 through 5 are expanded to include the months of October, November, and December.

Table 1 provides the MW of each resource type shown by CPUC-jurisdictional LSEs on their month ahead RA plans to meet system RA requirements from January through December 2019.

Resources procured to meet reliability needs by the IOUs and allocated to all customers through the cost allocation mechanism (CAM) are listed under CAM/RMR/LCR resources unless their capacity was later sold to another LSE. Combined heat and power (CHP) and demand response procured through the demand response auction mechanism (DRAM) are allocated in the same manner as CAM resources and are included under CAM.[3]

LSEs also receive a credit for any RA capacity procured by the CAISO as reliability must run (RMR) resources. LSEs serving load in the Southern California Edison (SCE) transmission access charge (TAC) area receive a local capacity requirement (LCR) credit for behind-the-meter resources procured to meet reliability needs in the Los Angeles Basin. These resources are included under RMR/LCR/DRAM PRM with the planning reserve margin adder CPUC credits to DRAM resources. Capacity from utility demand response programs is also allocated to all LSEs by TAC area and shown here as DR Credit. CAM Natural Gas MW were adjusted to account for outages so that resources shown in Table 1 equal the CAM credit shown in Table 3.

As seen below, natural gas generators comprise the majority of RA resources for IOUs, CCAs, and ESPs and can account for approximately two thirds of total RA capacity in some months.

[3] A list of 2019 CAM resources is available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442461336.

Table 1: Resources Shown on Month Ahead System RA Plans by LSE Type (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Battery Storage	85	81	80	80	82	80	79	93	92	89	87	80
	Biogas & Biomass	285	267	227	245	236	360	327	325	346	250	208	242
	CHP	1,465	1,429	1,305	1,224	1,299	1,553	1,380	1,496	1,455	1,356	1,318	1,349
	Demand Response	121	188	180	231	257	258	323	289	235	204	191	192
	Geothermal	1,155	1,101	1,066	1,029	1,036	1,073	1,075	1,036	1,035	1,070	1,006	1,079
	Hydro	2,117	1,755	2,528	2,297	2,650	4,030	4,081	3,978	3,729	3,046	3,005	2,924
	Natural Gas	22,146	21,081	20,255	20,134	20,691	22,452	23,197	24,482	24,629	23,626	22,696	21,961
	Nuclear	1,846	1,659	1,337	1,498	2,668	2,869	2,888	2,869	2,857	2,057	94	1,755
	Pumped Hydro	1,256	1,258	883	976	1,457	1,457	1,457	1,457	1,457	1,084	948	1,258
	Solar	10	189	716	2,480	2,403	4,335	4,117	4,105	3,388	2,223	264	21
	Unspecified Import	944	928	832	919	1,806	2,320	3,736	3,968	4,737	2,409	1,416	866
	Wind	602	895	975	1,609	1,708	2,567	1,630	1,487	1,514	454	327	522
	DR Credit	937	973	989	1,182	1,335	1,515	1,586	1,612	1,549	1,549	1,549	1,549
	RMR/LCR/ DRAM PRM	316	372	373	336	345	361	367	370	367	367	367	367
	Total	**33,284**	**32,176**	**31,744**	**34,238**	**37,972**	**45,229**	**46,243**	**47,568**	**47,389**	**39,783**	**33,475**	**34,164**
	CPUC RA Requirement	**30,953**	**30,827**	**30,032**	**32,928**	**36,803**	**44,540**	**45,992**	**47,176**	**47,881**	**39,332**	**31,716**	**32,397**
	% of Requirement	**108%**	**104%**	**106%**	**104%**	**103%**	**102%**	**101%**	**101%**	**99%**	**101%**	**106%**	**105%**
IOU	Battery Storage	6	2			2		2	4	3			
	Biogas & Biomass	165	117	107	142	121	208	217	171	178	111	75	120
	CHP	397	198	314	173	302	478	429	465	418	230	48	312
	Geothermal	931	869	863	852	855	851	858	863	858	866	819	876
	Hydro	1,239	1,088	1,432	1,497	1,490	2,748	2,788	2,761	2,806	2,215	2,253	1,746
	Natural Gas	10,487	9,147	9,005	8,682	8,504	9,342	10,599	11,805	11,457	10,546	10,102	9,034
	Nuclear	1,741	1,606	1,337	1,498	2,416	1,875	2,068	1,877	2,085	1,869		1,591
	Pumped Hydro	919	1,133	744	259	1,339	1,313	1,389	1,239	1,084	953	751	1,082
	Solar	0	144	592	1,828	1,862	3,300	3,258	3,092	2,627	1,621	169	
	Unspecified Import	328	259	259	264	739	916	1,912	2,302	2,527	1,047	429	287
	Wind	538	770	841	1,287	1,423	2,103	1,411	1,258	1,267	376	254	397
	Total	**16,751**	**15,332**	**15,493**	**16,483**	**19,051**	**23,134**	**24,930**	**25,837**	**25,310**	**19,834**	**14,899**	**15,445**
CCA	Battery Storage							10	10	10			
	Biogas & Biomass	88	116	80	51	74	126	56	99	127	95	86	79
	CHP	47	280	1	123	115	47	49	27	46	231	351	59

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Demand Response								1	29			
	Geothermal	139	150	137	118	120	159	159	115	113	129	129	145
	Hydro	800	609	984	647	1,017	991	1,011	1,075	701	680	643	1,018
	Natural Gas	3,861	4,060	3,561	3,607	4,372	4,934	4,508	4,503	4,736	4,993	4,365	4,987
	Nuclear	105	53			167	868	745	902	697	178	91	164
	Pumped Hydro	306	85	136	650	85	116		218	338	17	171	176
	Solar	0	16	46	422	294	776	487	603	375	375	38	0
	Unspecified Import	161	286	124	235	627	924	1,291	1,090	1,661	802	516	227
	Wind	33	56	68	189	143	172	133	148	125	44	39	71
	Total	**5,539**	**5,712**	**5,138**	**6,043**	**7,015**	**9,112**	**8,449**	**8,790**	**8,957**	**7,544**	**6,428**	**6,926**
ESP	Battery Storage						2				9	9	
	Biogas & Biomass	32	34	40	51	41	27	53	56	41	43	48	44
	CHP	17	54	20	22	19	24	18	48	16	16	20	24
	Geothermal	85	82	66	59	61	63	58	58	64	75	58	58
	Hydro	78	58	111	153	143	290	282	142	222	151	109	160
	Natural Gas	1,822	1,846	1,756	1,843	1,799	1,906	1,850	1,948	2,234	2,057	2,016	1,879
	Nuclear					85	126	75	90	75	10	3	
	Pumped Hydro	31	40	2	66	33	29	68		35	114	25	
	Solar	10	29	78	231	248	259	372	410	385	226	57	21
	Unspecified Import	455	383	449	420	440	480	534	576	549	560	471	352
	Wind	31	69	66	132	142	291	86	82	121	35	35	54
	Total	**2,560**	**2,596**	**2,589**	**2,977**	**3,010**	**3,498**	**3,395**	**3,409**	**3,742**	**3,296**	**2,851**	**2,592**
CAM/ RMR/ LCR	Battery Storage	80	80	80	80	80	78	68	80	80	80	78	80
	CHP	1,004	897	969	905	864	1,003	884	955	976	878	900	953
	Demand Response	121	188	180	231	257	258	323	288	206	204	191	192
	Natural Gas	5,977	6,027	5,933	6,001	6,016	6,271	6,240	6,226	6,202	6,031	6,213	6,061
	DR Credit	937	973	989	1,182	1,335	1,515	1,586	1,612	1,549	1,549	1,549	1,549
	RMR/LCR/ DRAM PRM	316	372	373	336	345	361	367	370	367	367	367	367
	Total	**8,434**	**8,536**	**8,524**	**8,736**	**8,897**	**9,484**	**9,468**	**9,532**	**9,379**	**9,108**	**9,297**	**9,201**

In Table 1, dynamically scheduled imports and pseudo-ties (resources located outside of the California Independent System Operator (CAISO) balancing area that bid into the CAISO market as individual resources) are listed under their resource type (nuclear, hydro, solar, etc.), while unspecified imports are listed separately. Table 2 shows total imports for each month when unspecified imports are combined with dynamically scheduled imports and pseudo-ties.

Table 2: All Imports Shown on 2019 Month Ahead RA Plans by LSE Type (MW)

LSE Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IOU	1,398	1,134	1,337	935	1,434	2,068	3,061	3,505	3,664	1,953	800	1,318
CCA	161	286	124	235	627	924	1,291	1,090	1,661	802	516	227
ESP	455	383	449	420	440	480	602	644	603	607	477	352
Total	**2,014**	**1,803**	**1,910**	**1,590**	**2,501**	**3,472**	**4,954**	**5,238**	**5,928**	**3,362**	**1,793**	**1,897**

Table 3 shows the contribution of internal resources, imports, CAM, RMR, LCR and DR towards meeting RA requirements by LSE type. On aggregate, LSEs have met RA requirements in most months, though there was an approximately 500 MW cumulative deficiency in September resulting from the five LSE month ahead system deficiencies described in Section 4.

Table 3: Resource Types Used to Meet 2019 System Requirements on Monthly RA Plans (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Internal Resources	22,836	21,836	21,311	23,913	26,575	32,273	31,821	32,798	32,081	27,312	22,385	23,066
		69%	68%	67%	70%	70%	71%	69%	69%	68%	69%	69%	69%
	Imports	2,014	1,803	1,910	1,590	2,501	3,472	4,954	5,238	5,928	3,362	1,793	1,897
		6%	6%	6%	5%	7%	8%	11%	11%	13%	9%	6%	6%
	CAM/RMR/ LCR Credit	7,496	7,563	7,535	7,553	7,561	7,970	7,882	7,919	7,830	7,446	6,995	7,381
		23%	24%	24%	22%	20%	18%	17%	17%	17%	19%	22%	22%
	DR Credit	937	972	989	1,182	1,335	1,514	1,585	1,612	1,549	1,332	1,060	948
		3%	3%	3%	3%	4%	3%	3%	3%	3%	3%	3%	3%
	Total	**33,283**	**32,175**	**31,744**	**34,238**	**37,972**	**45,229**	**46,242**	**47,567**	**47,389**	**39,453**	**32,233**	**33,292**
		100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
	CPUC RA Requirement	**30,953**	**30,827**	**30,032**	**32,928**	**36,803**	**44,540**	**45,992**	**47,176**	**47,881**	**39,332**	**31,716**	**32,397**
	% Shown	**108%**	**104%**	**106%**	**104%**	**103%**	**102%**	**101%**	**101%**	**99%**	**100%**	**102%**	**103%**
IOU	Internal Resources	15,352	14,198	14,156	15,548	17,617	21,067	21,869	22,332	21,645	17,881	14,099	14,127
		66%	66%	66%	69%	70%	71%	69%	68%	68%	70%	71%	68%
	Imports	1,398	1,134	1,337	935	1,434	2,068	3,061	3,505	3,664	1,953	800	1,318
		6%	5%	6%	4%	6%	7%	10%	11%	12%	8%	4%	6%

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	CAM/RMR/ LCR Credit	5,714	5,379	5,322	5,252	5,137	5,482	5,703	5,727	5,421	4,871	4,275	4,819
		25%	25%	25%	23%	20%	18%	18%	18%	17%	19%	22%	23%
	DR Credit	744	716	722	858	917	1,024	1,135	1,163	1,065	895	706	650
		3%	3%	3%	4%	4%	3%	4%	4%	3%	3%	4%	3%
	Total	**23,208**	**21,428**	**21,537**	**22,593**	**25,105**	**29,640**	**31,768**	**32,727**	**31,795**	**25,600**	**19,880**	**20,914**
		100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
	IOU RA Requirement	**22,420**	**20,623**	**20,590**	**21,942**	**24,317**	**29,128**	**31,604**	**32,528**	**31,689**	**25,608**	**19,783**	**20,738**
	% Shown	**104%**	**104%**	**105%**	**103%**	**103%**	**102%**	**101%**	**101%**	**100%**	**100%**	**100%**	**101%**
CCA	Internal Resources	5,378	5,426	5,014	5,808	6,388	8,188	7,159	7,701	7,297	6,742	5,912	6,699
		81%	75%	75%	76%	72%	74%	70%	73%	67%	71%	70%	75%
	Imports	161	286	124	235	627	924	1,291	1,090	1,661	802	516	227
		2%	4%	2%	3%	7%	8%	13%	10%	15%	8%	6%	3%
	CAM/RMR/ LCR Credit	982	1,317	1,342	1,400	1,577	1,652	1,449	1,496	1,624	1,689	1,771	1,750
		15%	18%	20%	18%	18%	15%	14%	14%	15%	18%	21%	20%
	DR Credit	104	158	166	199	288	349	320	324	339	295	237	214
		2%	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%	2%
	Total	**6,626**	**7,187**	**6,646**	**7,641**	**8,880**	**11,113**	**10,219**	**10,610**	**10,921**	**9,528**	**8,436**	**8,889**
		100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
	CCA RA Requirement	**5,431**	**6,913**	**6,111**	**7,291**	**8,700**	**11,056**	**10,309**	**10,538**	**11,577**	**9,456**	**8,260**	**8,464**
	% Shown	**122%**	**104%**	**109%**	**105%**	**102%**	**101%**	**99%**	**101%**	**94%**	**101%**	**102%**	**105%**
ESP	Internal Resources	2,105	2,212	2,140	2,557	2,570	3,018	2,793	2,765	3,139	2,689	2,374	2,240
		61%	62%	60%	64%	64%	67%	66%	65%	67%	62%	61%	64%
	Imports	455	383	449	420	440	480	602	644	603	607	477	352
		13%	11%	13%	10%	11%	11%	14%	15%	13%	14%	12%	10%
	CAM/RMR/ LCR Credit	800	867	871	901	847	836	730	696	785	886	949	812
		23%	24%	24%	23%	21%	19%	17%	16%	17%	20%	24%	23%
	DR Credit	89	98	101	125	130	142	130	125	146	142	117	85
		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%
	Total	**3,449**	**3,560**	**3,561**	**4,004**	**3,987**	**4,477**	**4,255**	**4,230**	**4,673**	**4,324**	**3,917**	**3,489**
		100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
	ESP RA Requirement	**3,102**	**3,291**	**3,331**	**3,695**	**3,786**	**4,355**	**4,079**	**4,110**	**4,615**	**4,268**	**3,673**	**3,195**
	% Shown	**111%**	**108%**	**107%**	**108%**	**105%**	**103%**	**104%**	**103%**	**101%**	**101%**	**107%**	**109%**

Since local RA requirements are based on a study of peak August load by the CAISO but applied to each month of the year, CPUC has adopted rules to count local resources at their August NQC values for all months when evaluating compliance with local requirements. Therefore, Table 1 uses monthly values for resources with NQC values that vary, while Table 4 employs the CPUC counting convention of counting local resources at their August NQC values for all months in presenting similar information on resources procured to meet local RA requirements.

Table 4: Resources Shown on 2019 Month Ahead Local RA Plans by LSE Type (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Battery Storage	83	80	80	80	83	82	83	83	83	80	78	80
	Biogas & Biomass	133	163	148	122	148	166	157	156	135	129	135	130
	CHP	954	873	1,029	984	1,159	1,165	1,171	1,151	1,152	903	995	942
	Geothermal	474	482	453	427	431	472	467	423	420	729	712	728
	Hydro	1,690	1,841	2,219	1,959	1,985	2,379	2,383	2,208	2,106	2,192	2,558	2,490
	Natural Gas	16,146	16,084	15,590	15,493	15,927	15,975	16,032	16,959	16,475	17,279	16,010	16,365
	Pumped Hydro	1,256	1,258	883	976	1,258	1,223	1,258	1,231	1,258	885	948	1,258
	Solar	606	823	667	772	814	895	904	908	890	731	725	529
	Wind	440	452	446	480	464	508	475	469	469	383	375	433
	DR Credit	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190
	RMR/LCR/ DRAM	499	499	499	522	522	522	522	522	522	522	522	522
	Total	**23,471**	**23,746**	**23,203**	**23,005**	**23,982**	**24,576**	**24,642**	**25,299**	**24,699**	**25,023**	**24,248**	**24,665**
	CPUC Requirement	**22,104**	**21,931**	**21,936**	**21,972**	**22,376**	**22,254**	**22,733**	**22,733**	**22,733**	**22,733**	**22,733**	**22,733**
	% of Requirement	**106%**	**108%**	**106%**	**105%**	**107%**	**110%**	**108%**	**111%**	**109%**	**110%**	**107%**	**108%**
IOU	Battery Storage	4				4		4	3	3			
	Biogas & Biomass	53	52	53	54	67	80	83	59	60	48	39	35
	CHP	407	195	405	187	375	456	411	407	458	185	66	317
	Geothermal	250	250	250	250	250	250	250	250	250	525	525	525
	Hydro	866	1,263	1,375	1,396	1,094	1,560	1,413	1,374	1,417	1,520	1,866	1,476
	Natural Gas	8,400	7,832	7,037	7,720	7,788	7,580	7,925	8,168	7,820	8,307	7,329	7,511
	Pumped Hydro	919	1,133	744	259	1,140	1,114	1,190	1,040	885	754	751	1,082
	Solar	416	622	502	514	476	608	655	552	657	446	506	328
	Wind	359	359	359	333	359	359	359	359	359	312	311	359
	Total	**11,675**	**11,706**	**10,726**	**10,715**	**11,552**	**12,006**	**12,291**	**12,212**	**11,909**	**12,097**	**11,393**	**11,633**

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CCA	Biogas & Biomass	66	98	60	41	67	77	54	75	65	66	84	75
	CHP	47	228	1	112	80	1	48	22		185	304	13
	Geothermal	139	150	137	118	120	159	159	115	108	129	129	145
	Hydro	758	529	777	498	812	761	874	791	546	628	621	917
	Natural Gas	2,362	2,340	2,531	2,137	2,236	2,452	2,304	2,375	2,266	2,337	2,203	2,195
	Pumped Hydro	306	85	136	650	85	91		191	338	17	171	176
	Solar	65	75	91	160	226	200	145	195	94	200	90	75
	Wind	38	44	37	87	58	76	57	54	54	31	31	33
	Total	**3,780**	**3,550**	**3,772**	**3,804**	**3,685**	**3,816**	**3,641**	**3,817**	**3,471**	**3,593**	**3,633**	**3,630**
ESP	Battery Storage						2						
	Biogas & Biomass	14	14	34	27	14	10	20	22	10	15	12	19
	CHP	13	47	12	12	9	13	17	44	11	11	14	15
	Geothermal	85	82	66	59	61	63	58	58	62	75	58	58
	Hydro	66	48	68	65	79	58	95	43	143	43	71	97
	Natural Gas	1,430	1,445	1,457	1,409	1,422	1,462	1,323	1,409	1,361	1,440	1,486	1,450
	Pumped Hydro	31	40	2	66	33	19	68		35	114	25	
	Solar	125	126	73	97	112	87	103	161	139	85	129	126
	Wind	43	49	50	60	47	73	59	56	56	39	34	40
	Total	**1,806**	**1,851**	**1,761**	**1,794**	**1,778**	**1,788**	**1,743**	**1,793**	**1,817**	**1,822**	**1,830**	**1,806**
CAM/ RMR/ LCR Credit	Battery Storage	80	80	80	80	80	80	80	80	80	80	78	80
	CHP	488	403	610	673	695	695	695	678	683	523	611	596
	Natural Gas	3,953	4,468	4,565	4,227	4,481	4,481	4,481	5,007	5,027	5,196	4,992	5,209
	DR Credit	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190
	RMR/LCR/DR AM	499	499	499	522	522	522	522	522	522	522	522	522
	Total	**6,209**	**6,639**	**6,944**	**6,692**	**6,967**	**6,967**	**6,967**	**7,477**	**7,501**	**7,510**	**7,392**	**7,596**

Table 5 shows the same resources as Table 4, but breaks down showings by local area rather than LSE type. Table 5 indicates that, despite the deficiencies described in Section 4, CPUC-jurisdictional LSEs have, in aggregate, provided sufficient capacity for all local areas except San Diego-Imperial Valley (San Diego-IV), which had deficiencies during the peak months of July through September and November.

Table 5: Resources Shown on 2019 Month Ahead Local RA Plans by Local Area (MW)

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	Battery Storage	4				4	2	4	3	3			
	Biogas & Biomass	4	5	6	1	1	5	3	0	0			5
	CHP	236	236	233	121	230	233	232	236	233	231	236	237
	Natural Gas	3,926	3,768	3,863	3,819	3,835	3,842	3,758	3,715	3,750	4,675	3,717	3,984
	Solar	4	12	12	12	12	12	12	12	12	12	12	4
	Wind	184	185	181	191	189	193	189	188	188	183	183	181
	DR Credit	116	116	116	116	116	116	116	116	116	116	116	116
	RMR/DRAM	203	203	203	203	203	203	203	203	203	203	203	203
	Total	**4,677**	**4,525**	**4,614**	**4,463**	**4,590**	**4,606**	**4,516**	**4,473**	**4,505**	**5,421**	**4,467**	**4,730**
	CPUC Requirement	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**	**4,031**
	% of Requirement	**116%**	**112%**	**114%**	**111%**	**114%**	**114%**	**112%**	**111%**	**112%**	**134%**	**111%**	**117%**
Big Creek-Ventura	Biogas & Biomass	21	21	21	21	21	35	30	30	30	19	11	11
	CHP	418	333	333	394	418	418	418	413	403	236	252	288
	Hydro	352	437	486	377	352	352	352	352	363	577	630	639
	Natural Gas	1,431	1,431	1,372	1,430	1,430	1,430	1,430	1,430	1,432	1,385	1,369	1,366
	Solar	67	107	82	148	148	185	162	147	176	99	78	19
	DR Credit	169	169	169	169	169	169	169	169	169	169	169	169
	DRAM	10	10	10	10	10	10	10	10	10	10	10	10
	Total	**2,459**	**2,499**	**2,463**	**2,538**	**2,538**	**2,589**	**2,562**	**2,541**	**2,573**	**2,495**	**2,519**	**2,502**
	CPUC Requirement	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**	**2,390**
	% of Requirement	**103%**	**105%**	**103%**	**106%**	**106%**	**108%**	**107%**	**106%**	**108%**	**104%**	**105%**	**105%**
LA Basin	Battery Storage	42	42	42	42	42	42	42	42	42	42	40	42
	Biogas & Biomass	2	2	2	2	2	2	2	2	2	2	2	2
	CHP	133	133	343	343	343	343	343	328	343	263	341	325
	Hydro	6	3	3	1	1	7	7	7	7	8	6	7
	Natural Gas	6,376	6,360	6,146	6,135	6,138	6,190	6,191	7,191	6,747	6,322	6,295	6,221
	Solar	31	31	31	31	31	31	31	31	28	19	24	
	Wind	131	142	141	165	151	190	162	157	157	75	68	127
	DR Credit	686	686	686	686	686	686	686	686	686	686	686	686
	LCR/DRAM	173	173	173	173	173	173	173	173	173	173	173	173
	Total	**7,580**	**7,572**	**7,567**	**7,578**	**7,567**	**7,664**	**7,637**	**8,617**	**8,184**	**7,590**	**7,635**	**7,583**
	CPUC Requirement	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**	**7,417**
	% of Requirement	**102%**	**102%**	**102%**	**102%**	**102%**	**103%**	**103%**	**116%**	**110%**	**102%**	**103%**	**102%**

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Other PG&E Areas	Biogas & Biomass	97	127	110	90	118	119	116	117	96	102	116	105
	CHP	162	166	114	122	163	166	166	166	166	166	159	84
	Geothermal	474	482	453	427	431	472	467	423	420	729	712	728
	Hydro	1,332	1,401	1,730	1,582	1,632	2,020	2,024	1,849	1,736	1,607	1,922	1,845
	Natural Gas	1,437	1,521	1,315	1,328	1,380	1,489	1,413	1,382	1,315	1,380	1,323	1,374
	Pumped Hydro	1,216	1,218	843	936	1,218	1,183	1,218	1,191	1,218	845	908	1,218
	Solar	176	345	214	253	296	339	371	390	346	267	283	178
	DR Credit	184	184	184	184	184	184	184	184	184	184	184	184
	RMR/DRAM	101	101	101	101	101	101	101	101	101	101.25	101.25	101.25
	Total	**5,179**	**5,545**	**5,065**	**5,023**	**5,522**	**6,073**	**6,060**	**5,804**	**5,583**	**5,381**	**5,708**	**5,817**
	CPUC Requirement	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**	**4,868**
	% of Requirement	**106%**	**114%**	**104%**	**103%**	**113%**	**125%**	**124%**	**119%**	**115%**	**111%**	**117%**	**119%**
San Diego-IV[4]	Battery Storage	38	38	38	38	38	38	38	38	38	38	38	38
	Biogas & Biomass	9	9	9	9	7	7	7	7	7	7	7	7
	CHP	5	5	5	5	5	5	11	7	7	7	7	7
	Natural Gas	2,975	3,005	2,894	2,780	3,144	3,023	3,240	3,241	3,231	3,518	3,307	3,420
	Pumped Hydro	40	40	40	40	40	40	40	40	40	40	40	40
	Solar	328	328	328	328	328	328	328	328	328	334	328	328
	Wind	125	125	125	125	125	125	125	125	125	125	125	125
	DR Credit	34	34	34	34	34	34	34	34	34	34	34	34
	DRAM	12	12	12	35	35	35	35	35	35	35	35	35
	Total	**3,566**	**3,595**	**3,485**	**3,394**	**3,755**	**3,634**	**3,857**	**3,855**	**3,844**	**4,136**	**3,920**	**4,033**
	CPUC Requirement	**3,398**	**3,225**	**3,230**	**3,266**	**3,670**	**3,548**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**
	% of Requirement	**105%**	**111%**	**108%**	**104%**	**102%**	**102%**	**96%**	**96%**	**95%**	**103%**	**97%**	**100%**

[4] The San Diego-IV requirement varies by month because CPUC caps LSE local requirements at their system requirement.

3. RESOURCES PROCURED FOR RA-2020 YEAR AHEAD FILINGS

In year ahead filings, LSEs must demonstrate that they have procured resources that meet 90% of their RA requirements for the summer months of May through September. Although there were individual deficiencies, on aggregate CPUC-jurisdictional LSEs met the total CPUC year ahead RA requirement. Table 6 indicates that similar to 2019, the bulk of capacity procured by all LSEs is natural gas.

Table 6: Resources Shown on 2020 Year Ahead (90%) System RA Plans by LSE Type (MW)

LSE Type	Resource Type	May	Jun	Jul	Aug	Sep
All	Battery Storage	99	118	135	132	135
	Biogas and Biomass	279	366	367	371	357
	CHP	1,167	1,316	1,343	1,348	1,286
	Demand Response	20	21	21	22	29
	Geothermal	985	996	1,017	1,008	1,010
	Hydro	3,277	3,949	3,857	3,819	3,723
	Natural Gas	24,858	25,765	25,781	25,512	25,603
	Nuclear	1,597	1,426	2,076	2,078	1,684
	Pumped Hydro	1,038	1,450	1,458	1,456	1,457
	Solar	1,539	3,343	4,046	2,774	1,653
	Unspecified Import	1,520	2,041	2,214	2,655	3,231
	Wind	1,233	1,813	1,302	1,154	845
	DR Credit	1,291	1,417	1,422	1,472	1,399
	RMR/LCR Credit	324	327	327	327	333
	Total	**39,227**	**44,347**	**45,366**	**44,128**	**42,746**
	CPUC RA Requirement (90%)	**33,272**	**38,054**	**42,001**	**42,376**	**42,403**
	% of Requirement	**118%**	**117%**	**108%**	**104%**	**101%**
IOU	Battery Storage	9	12	12	9	12
	Biogas and Biomass	67	119	121	127	125
	CHP	44	175	198	172	152
	Geothermal	652	694	702	702	713
	Hydro	2,501	3,127	2,885	3,004	2,768
	Natural Gas	10,945	10,760	10,974	11,140	11,120
	Nuclear	1,597	1,426	2,076	1,907	1,684
	Pumped Hydro	946	1,402	1,372	1,238	1,369
	Solar	1,109	2,730	3,215	2,153	1,397

LSE Type	Resource Type	May	Jun	Jul	Aug	Sep
	Unspecified Import	152	569	568	563	1,225
	Wind	1,006	1,465	1,043	936	679
	Total	**19,028**	**22,480**	**23,166**	**21,951**	**21,244**
CCA	Battery Storage	10	25	25	25	25
	Biogas and Biomass	195	220	199	211	198
	CHP	131	112	127	154	114
	Demand Response	20	21	21	22	29
	Geothermal	265	234	247	238	229
	Hydro	528	547	644	617	681
	Natural Gas	5,197	5,638	5,438	4,680	4,795
	Nuclear				151	
	Pumped Hydro	73	37	48	153	77
	Solar	293	420	605	452	136
	Unspecified Import	1,220	1,324	1,337	1,783	1,697
	Wind	130	222	163	116	92
	Total	**8,062**	**8,800**	**8,854**	**8,602**	**8,073**
ESP	Biogas and Biomass	17	27	47	33	34
	CHP	83	84	83	86	87
	Geothermal	68	68	68	68	68
	Hydro	248	275	328	198	274
	Natural Gas	2,083	2,125	2,004	2,129	2,111
	Nuclear				20	
	Pumped Hydro	19	11	38	65	11
	Solar	137	193	226	169	120
	Unspecified Import	148	148	309	309	309
	Wind	97	126	96	102	74
	Total	**2,900**	**3,057**	**3,199**	**3,179**	**3,088**
CAM/RMR/LCR Credit	Battery Storage	80	81	98	98	98
	CHP	909	945	935	936	933
	Natural Gas	6,634	7,242	7,365	7,564	7,577
	DR Credit	1,291	1,417	1,422	1,472	1,399
	RMR/LCR Credit	324	327	327	327	333
	Total	**9,238**	**10,012**	**10,146**	**10,397**	**10,340**

Table 7 provides the total amount of imports procured to meet year ahead requirements. This includes both the unspecified imports that are broken out in Table 6, and those categorized by resource type above.

Table 7: All Imports Shown on 2019 Month Ahead RA Plans by LSE Type (MW)

LSE Type	May	Jun	Jul	Aug	Sep
IOU	1,298	1,763	1,743	1,713	2,323
CCA	1,220	1,324	1,337	1,783	1,697
ESP	180	191	358	349	339
Total	**2,698**	**3,278**	**3,438**	**3,844**	**4,359**

Table 8 shows the contribution of internal resources, imports, CAM, RMR, LCR and DR towards meeting RA requirements by LSE type. On aggregate, each LSE type met year ahead system RA requirements. Overall about 70% of RA capacity is comprised of internal resources, 7-10% is imports, about 20% is CAM, RMR and LCR resources and the remaining 3% is IOU DR programs.

Table 8: Resource Types Used to Meet 2020 System Requirements (90%) on Year Ahead RA Plans (MW)

LSE Type	Resource Type	May	Jun	Jul	Aug	Sep
All	Internal Resources	27,323	31,102	31,831	29,927	28,077
		70%	70%	70%	68%	66%
	Imports	2,666	3,235	3,389	3,804	4,328
		7%	7%	7%	9%	10%
	CAM/RMR/LCR Credit	7,534	8,594	8,724	8,925	8,940
		19%	19%	19%	20%	21%
	DR Credit	1,291	1,417	1,422	1,472	1,399
		3%	3%	3%	3%	3%
	Total	**38,814**	**44,347**	**45,365**	**44,128**	**42,745**
		100%	**100%**	**100%**	**100%**	**100%**
	CPUC RA Requirement	**33,275**	**38,054**	**41,438**	**41,832**	**41,787**
	% Shown	**117%**	**117%**	**109.5%**	**105%**	**102%**
IOU	Internal Resources	17,730	20,717	21,423	20,238	18,921
		71%	70%	71%	69%	66%
	Imports	1,298	1,763	1,743	1,713	2,323
		5%	6%	6%	6%	8%
	CAM/RMR/LCR Credit	5,123	6,021	6,111	6,452	6,541
		20%	20%	20%	22%	23%
	DR Credit	876	968	969	1,006	968
		3%	3%	3%	3%	3%

LSE Type	Resource Type	May	Jun	Jul	Aug	Sep
	Total	25,026	29,469	30,245	29,409	28,753
		100%	100%	100%	100%	100%
	IOU RA Requirement	21,899	25,318	27,573	27,889	28,193
	% Shown	114%	116%	110%	105%	102%
CCA	Internal Resources	6,842	7,476	7,517	6,819	6,376
		69%	69%	69%	64%	63%
	Imports	1,220	1,324	1,337	1,783	1,697
		12%	12%	12%	17%	17%
	CAM/RMR/LCR Credit	1,558	1,708	1,771	1,701	1,666
		16%	16%	16%	16%	17%
	DR Credit	283	317	325	336	312
		3%	3%	3%	3%	3%
	Total	9,903	10,824	10,950	10,639	10,051
		100%	100%	100%	100%	100%
	CCA RA Requirement	7,992	9,156	10,053	10,117	9,886
	% Shown	124%	118%	109%	105%	102%
ESP	Internal Resources	2,752	2,909	2,891	2,870	2,780
		71%	72%	69%	70%	71%
	Imports	148	148	309	309	309
		4%	4%	7%	8%	8%
	CAM/RMR/LCR Credit	853	865	842	771	733
		22%	21%	20%	19%	19%
	DR Credit	132	132	128	131	120
		3%	3%	3%	3%	3%
	Total	3,885	4,054	4,170	4,080	3,940
		100%	100%	100%	100%	100%
	ESP RA Requirement	3,384	3,580	3,812	3,825	3,708
	% Shown	115%	113%	109%	107%	106%

In Decision 19-02-022, the CPUC made two significant changes to local RA requirements for 2020. The biggest change is that there is now a three-year local RA requirement which requires each LSE to procure capacity to meet 100% of its local requirements for 2020 and 2021 and 50% of its local requirement of 2022. Table 9, 10, and 11 show the capacity procured to meet year ahead local requirements for 2020, 2021 and 2022, respectively. In aggregate, LSEs procured sufficient local MW to meet the applicable local RA requirements for each year. However, there were collective deficiencies among CPUC jurisdictional LSEs in some local areas as detailed below in

Table 12.

Table 9: Resources Shown on 2020 Year Ahead Local RA Plans by LSE Type (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Battery Storage	83	80	83	84	84	85	85	85	85	85	85	270
	Biogas and Biomass	189	180	165	168	161	175	168	177	173	172	145	151
	CHP	848	835	823	789	738	807	849	855	838	821	817	850
	Demand Response	2	2	2	2	3	3	3	4	3	3	2	2
	Geothermal	635	635	635	635	635	635	645	645	635	635	635	635
	Hydro	2,096	1,944	1,894	1,927	1,953	1,960	1,920	1,721	1,971	1,933	1,909	1,997
	Natural Gas	15,599	15,457	15,436	15,636	15,504	15,367	15,250	15,211	15,273	15,386	15,457	15,369
	Pumped Hydro	532	847	851	808	839	713	802	1,113	795	839	958	894
	Solar	380	382	396	424	391	419	430	408	394	407	392	408
	Wind	327	321	369	293	290	317	290	284	273	252	267	272
	DR Credit	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
	RMR/LCR Credit	319	319	319	319	319	319	319	319	319	319	319	319
	Total	**22,087**	**22,079**	**22,050**	**22,160**	**21,993**	**21,876**	**21,838**	**21,899**	**21,835**	**21,928**	**22,062**	**22,244**
	CPUC Requirement	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**	**21,721**
	% of Total	**102%**	**102%**	**102%**	**102%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**102%**	**102%**
IOU	Battery Storage	3	0	3	4	4	4	4	4	4	4	4	39
	Biogas and Biomass	51	47	41	52	52	51	41	52	52	52	52	52
	CHP	153	150	142	43	36	148	175	152	167	158	163	198
	Geothermal	342	342	342	342	342	342	342	342	342	342	342	342
	Hydro	1,369	1,277	1,320	1,264	1,266	1,282	1,253	1,139	1,348	1,308	1,283	1,448
	Natural Gas	7,268	7,182	7,036	7,290	6,641	5,966	5,911	5,869	5,862	6,051	5,979	5,981
	Pumped Hydro	409	619	708	601	747	665	717	895	707	710	721	584
	Solar	259	256	255	295	258	253	254	259	270	276	261	306
	Wind	246	246	248	182	203	182	181	194	180	179	201	180
	Total	**10,100**	**10,119**	**10,095**	**10,073**	**9,549**	**8,893**	**8,878**	**8,906**	**8,932**	**9,080**	**9,006**	**9,130**
CCA	Biogas and Biomass	128	122	113	106	98	113	114	115	111	104	83	89
	CHP	142	135	134	205	154	110	127	151	119	124	109	109
	Demand Response	2	2	2	2	3	3	3	4	3	3	2	2
	Geothermal	225	225	225	225	225	225	235	235	225	225	225	225
	Hydro	539	479	378	478	478	481	434	404	419	382	428	369

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Natural Gas	2,322	2,334	2,358	2,231	2,273	2,254	2,265	2,245	2,272	2,268	2,409	2,424
	Pumped Hydro	98	146	106	166	73	37	48	153	77	108	172	220
	Solar	96	101	104	95	99	119	120	104	93	107	107	80
	Wind	51	46	83	75	51	95	74	56	62	45	36	62
	Total	**3,603**	**3,591**	**3,503**	**3,583**	**3,454**	**3,437**	**3,420**	**3,467**	**3,381**	**3,366**	**3,571**	**3,579**
ESP	Biogas and Biomass	10	11	11	10	11	11	13	10	10	16	10	10
	CHP	37	34	31	35	32	33	31	36	36	30	36	34
	Geothermal	68	68	68	68	68	68	68	68	68	68	68	68
	Hydro	188	188	196	185	209	197	233	178	204	243	198	180
	Natural Gas	1,260	1,192	1,289	1,313	1,282	1,292	1,218	1,241	1,283	1,209	1,212	1,311
	Pumped Hydro	25	82	37	41	19	11	38	65	11	21	66	91
	Solar	25	25	38	34	35	48	56	45	31	24	24	23
	Wind	30	29	37	36	36	40	35	34	31	27	29	30
	Total	**1,643**	**1,629**	**1,707**	**1,721**	**1,691**	**1,699**	**1,691**	**1,677**	**1,674**	**1,638**	**1,643**	**1,746**
CAM/ RMR/ LCR	Battery Storage	80	80	80	80	80	81	81	81	81	81	81	231
	CHP	516	516	516	506	516	516	516	516	516	509	509	509
	Natural Gas	4,749	4,749	4,753	4,802	5,308	5,855	5,856	5,856	5,856	5,858	5,857	5,653
	DR Credit	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,076
	RMR/LCR Credit	319	319	319	319	319	319	319	319	319	319	319	319
	Total	**6,740**	**6,740**	**6,744**	**6,783**	**7,299**	**7,847**	**7,848**	**7,848**	**7,848**	**7,843**	**7,842**	**7,788**

Table 10: Resources Shown on 2021 Year Ahead Local RA Plans by LSE Type (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Battery Storage	639	639	670	667	667	1,007	1,010	1,010	1,016	1,013	1,013	1,091
	Biogas and Biomass	151	154	159	152	144	164	151	150	145	151	152	160
	CHP	753	755	756	698	729	723	684	690	689	680	689	692
	Demand Response	17	17	17	18	18	20	20	20	19	18	17	17
	Geothermal	593	593	593	593	593	593	593	593	593	593	593	593
	Hydro	2,622	2,224	2,232	2,344	2,366	2,348	2,415	2,300	2,494	2,370	2,300	2,407
	Natural Gas	14,232	14,137	14,117	14,195	14,165	13,879	13,799	13,710	13,722	13,706	13,754	13,660
	Pumped Hydro	600	1,088	1,133	1,009	1,005	1,019	1,022	1,265	1,006	1,002	1,182	1,000
	Solar	542	543	568	593	618	593	624	580	569	539	533	538
	Solar Hybrid	0	0	0	0	0	41.175	103.5	85.5	66	48	48	45
	Wind	308	310	292	267	268	283	257	257	297	204	228	238
	DR Credit	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057
	RMR/LCR Credit	344	344	344	344	344	344	344	344	344	344	344	344
	Total	**21,858**	**21,861**	**21,939**	**21,936**	**21,974**	**22,072**	**22,079**	**22,062**	**22,017**	**21,724**	**21,910**	**21,842**
	CPUC Requirement	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**	**21,728**
	% of Total	**101%**	**101%**	**101%**	**101%**	**101%**	**102%**	**102%**	**102%**	**101%**	**100%**	**101%**	**101%**
IOU	Battery Storage	62	62	62	59	59	59	62	62	62	59	59	62
	Biogas and Biomass	57	64	64	55	62	68	66	56	65	65	65	65
	CHP	259	259	280	220	242	265	267	258	272	256	260	272
	Geothermal	310	310	310	319	310	310	310	310	310	318	310	310
	Hydro	2,012	1,662	1,665	1,703	1,694	1,714	1,724	1,673	1,820	1,823	1,695	1,875
	Natural Gas	5,304	5,254	5,189	5,425	5,341	5,047	5,025	4,926	4,874	4,964	4,938	4,873
	Pumped Hydro	486	872	962	759	802	815	827	1,010	846	833	979	745
	Solar	378	378	380	408	429	382	394	376	383	378	373	386
	Wind	251	255	212	203	214	211	178	196	232	159	169	169
	Total	**9,119**	**9,116**	**9,124**	**9,151**	**9,153**	**8,871**	**8,853**	**8,867**	**8,864**	**8,855**	**8,848**	**8,757**
CCA	Battery Storage	5	5	5	5	5	5	5	5	5	5	5	5
	Biogas and Biomass	77	76	81	83	67	71	49	59	50	66	73	81
	CHP	73	70	55	57	66	61	63	73	58	70	72	61
	Demand Response	17	17	17	18	18	20	20	20	19	18	17	17
	Geothermal	216	216	216	216	216	216	216	216	216	216	216	216

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Hydro	390	364	361	410	448	401	434	395	439	303	410	345
	Natural Gas	2,364	2,309	2,329	2,174	2,268	2,295	2,234	2,255	2,296	2,211	2,259	2,228
	Pumped Hydro	88	168	144	250	168	159	185	202	125	152	176	233
	Solar	135	134	152	148	152	175	194	168	150	132	132	130
	Solar Hybrid	0	0	0	0	0	41	104	86	66	48	48	45
	Wind	34	39	65	49	39	62	64	51	55	34	44	54
	Total	**3,399**	**3,398**	**3,425**	**3,409**	**3,448**	**3,506**	**3,566**	**3,530**	**3,478**	**3,256**	**3,453**	**3,415**
ESP	Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0
	Biogas and Biomass	17	14	14	14	15	25	36	35	30	20	14	14
	CHP	1	6	1	1	1	6	1	6	6	1	4	6
	Geothermal	67	67	67	58	67	67	67	67	67	59	67	67
	Hydro	220	198	206	231	224	233	257	232	235	244	195	187
	Natural Gas	1,154	1,164	1,184	1,208	1,171	1,157	1,157	1,144	1,167	1,145	1,171	1,174
	Pumped Hydro	26	48	27	0	35	45	10	52	35	16	26	21
	Solar	29	31	37	37	37	37	37	37	37	28	28	22
	Wind	23	15	15	15	15	10	15	10	10	10	15	15
	Total	**1,537**	**1,544**	**1,551**	**1,564**	**1,565**	**1,580**	**1,580**	**1,583**	**1,587**	**1,524**	**1,520**	**1,506**
CAM/ RMR/ LCR	Battery Storage	572	572	603	603	603	943	943	943	949	949	949	1,024
	CHP	420	420	420	420	420	391	353	353	353	353	353	353
	Natural Gas	5,410	5,410	5,415	5,388	5,385	5,380	5,383	5,385	5,385	5,386	5,386	5,385
	DR Credit	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057
	RMR/LCR Credit	344	344	344	344	344	344	344	344	344	344	344	344
	Total	**7,803**	**7,803**	**7,839**	**7,812**	**7,809**	**8,115**	**8,080**	**8,082**	**8,088**	**8,089**	**8,089**	**8,163**

Table 11: Resources Shown on 2022 Year Ahead Local RA Plans by LSE Type (MW)

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All	Battery Storage	995	992	992	992	992	992	992	992	992	992	992	992
	Biogas and Biomass	128	110	117	109	100	107	103	113	97	102	100	103
	CHP	651	653	653	629	667	664	414	417	419	415	422	423
	Demand Response	2	2	2	2	2	2	2	2	2	2	2	2
	Geothermal	372	372	372	372	372	372	372	372	372	372	372	372
	Hydro	1,275	1,198	1,195	1,202	1,222	1,231	1,304	1,116	1,259	1,090	1,312	1,286
	Natural Gas	8,443	8,490	8,448	8,510	8,326	8,427	8,576	8,620	8,654	8,596	8,468	8,471
	Pumped Hydro	345	392	433	332	427	336	403	505	327	394	378	400
	Solar	468	467	485	516	545	561	565	558	539	523	523	526
	Solar Hybrid	96.12	93.34	135	126.7	129.5	171.2	193.4	160.06	123.92	90.56	90.56	85
	Wind	208	202	252	233	233	254	226	220	204	179	191	194
	DR Credit	513	513	513	513	513	513	513	513	513	513	513	513
	RMR/LCR Credit	169	169	169	169	169	169	169	169	169	169	169	169
	Total	13,666	13,654	13,766	13,705	13,697	13,800	13,833	13,758	13,671	13,438	13,533	13,536
	CPUC Requirement	10,408	10,408	10,408	10,408	10,408	10,408	10,408	10,408	10,408	10,408	10,408	10,408
	% of Total	131%	131%	132%	132%	132%	133%	133%	132%	131%	129%	130%	130%
IOU	Battery Storage	66	63	63	63	63	63	63	63	63	63	63	63
	Biogas and Biomass	54	41	43	48	49	46	43	53	42	42	42	41
	CHP	221	221	221	221	260	260	260	260	260	260	309	309
	Geothermal	153	153	153	153	153	153	153	153	153	153	153	153
	Hydro	768	715	714	719	691	753	782	693	784	732	838	861
	Natural Gas	1,920	2,019	1,926	2,034	1,960	2,007	2,216	2,250	2,237	2,233	2,073	2,075
	Pumped Hydro	345	319	409	257	406	311	364	409	326	378	378	351
	Solar	315	315	315	349	374	369	362	372	371	372	372	377
	Wind	170	168	183	180	180	187	177	175	169	157	162	163
	Total	**4,012**	**4,014**	**4,027**	**4,024**	**4,136**	**4,149**	**4,420**	**4,428**	**4,405**	**4,390**	**4,390**	**4,393**
CCA	Battery Storage	5	5	5	5	5	5	5	5	5	5	5	5
	Biogas and Biomass	67	62	67	54	44	54	53	53	48	43	49	53
	CHP	40	39	39	33	32	29	42	43	48	40	2	3
	Demand Response	2	2	2	2	2	2	2	2	2	2	2	2
	Geothermal	187	187	187	187	187	187	187	187	187	187	187	187

LSE Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Hydro	314	290	288	290	334	285	326	232	284	188	278	234
	Natural Gas	1,534	1,485	1,531	1,484	1,493	1,543	1,489	1,501	1,537	1,485	1,547	1,552
	Pumped Hydro		73	24	75	21	25	33	87	1	16		40
	Solar	132	131	149	145	149	170	182	165	147	129	129	127
	Solar Hybrid	96	93	135	127	129	171	193	160	124	91	91	85
	Wind	38	34	69	53	53	67	49	45	35	22	29	31
	Total	**2,415**	**2,401**	**2,495**	**2,454**	**2,449**	**2,539**	**2,561**	**2,481**	**2,417**	**2,208**	**2,319**	**2,319**
ESP	Battery Storage	18	18	18	18	18	18	18	18	18	18	18	18
	Biogas and Biomass	7	7	7	7	7	7	7	7	7	17	9	9
	CHP	2	5	5	5	5	5	2	4	1	5	1	1
	Geothermal	32	32	32	32	32	32	32	32	32	32	32	32
	Hydro	193	193	193	193	197	193	196	191	191	170	196	191
	Natural Gas	1,125	1,122	1,122	1,122	1,118	1,122	1,116	1,114	1,125	1,122	1,094	1,091
	Pumped Hydro							6	9				9
	Solar	22	22	22	22	22	22	22	22	22	22	22	22
	Total	**1,399**	**1,399**	**1,399**	**1,399**	**1,399**	**1,399**	**1,399**	**1,396**	**1,396**	**1,386**	**1,372**	**1,373**
CAM/ RMR/ LCR	Battery Storage	906	906	906	906	906	906	906	906	906	906	906	906
	CHP	388	388	388	370	370	370	110	110	110	110	110	110
	Natural Gas	3,864	3,864	3,869	3,870	3,755	3,755	3,755	3,755	3,755	3,756	3,754	3,753
	DR Credit	513	513	513	513	513	513	513	513	513	513	513	513
	RMR/LCR Credit	169	169	169	169	169	169	169	169	169	169	169	169
	Total	**5,840**	**5,840**	**5,845**	**5,828**	**5,713**	**5,713**	**5,453**	**5,453**	**5,453**	**5,454**	**5,452**	**5,451**

The other significant change in RA requirements that was introduced for 2020 was the disaggregation of the "PG&E Other" area. Fresno, Humboldt, Kern, North Coast/North Bay, Sierra, and Stockton were previously aggregated to one "PG&E Other" local area for compliance purposes, whereas now, local RA requirements are assigned for each of the 10 local areas separately. For 2020, aggregate deficiencies among CPUC jurisdictional LSEs were seen for the Bay Area, Big Creek-Ventura, Kern, North Coast/North Bay, San Diego-IV, Sierra and Stockton local areas as depicted in

Table 12.

Table 12: Resources Shown on 2020 Year Ahead Local RA Plans by Local Area (MW)

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	Battery Storage	3	0	0	0	0	0	0	0	0	0	0	0
	Biogas and Biomass	1	1	1	0	0	0	5	5	2	0	0	0
	CHP	230	226	215	199	122	197	230	231	216	215	199	231
	Natural Gas	3,441	3,455	3,424	3,586	3,557	3,436	3,412	3,416	3,443	3,453	3,517	3,504
	Solar	8	8	8	3	3	3	3	3	3	3	3	3
	Wind	137	133	165	94	90	111	90	86	80	66	77	81
	DR Credit	100	100	100	100	100	100	100	100	100	100	100	100
	RMR	148	148	148	148	148	148	148	148	148	148	148	148
	Total	**4,068**	**4,071**	**4,061**	**4,130**	**4,020**	**3,995**	**3,988**	**3,989**	**3,992**	**3,985**	**4,044**	**4,067**
	CPUC Requirement	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**	**4,087**
	% of Total	**100%**	**100%**	**99%**	**101%**	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**	**99%**	**100%**
Big Creek-Ventura	Battery Storage	0	0	1	1	1	1	1	1	1	1	1	151
	Biogas and Biomass	15	15	15	15	15	15	15	15	15	15	15	15
	CHP	160	160	160	150	160	160	160	160	160	160	160	160
	Hydro	227	227	227	227	227	227	227	227	227	227	227	227
	Natural Gas	1,496	1,496	1,496	1,496	1,496	1,496	1,496	1,496	1,496	1,496	1,496	1,395
	Solar	52	51	60	59	59	68	73	66	58	51	51	50
	DR Credit	137	137	137	137	137	137	137	137	137	137	137	137
	Total	**2,087**	**2,086**	**2,096**	**2,085**	**2,095**	**2,104**	**2,109**	**2,102**	**2,094**	**2,087**	**2,087**	**2,135**
	CPUC Requirement	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**	**2,183**
	% of Total	**96%**	**96%**	**96%**	**95%**	**96%**	**96%**	**97%**	**96%**	**96%**	**96%**	**96%**	**98%**
Fresno	Biogas and Biomass	41	36	43	43	43	43	43	43	43	43	22	20
	CHP	1	3	3	2	2	2	3	3	3	2	2	3
	Hydro	407	256	248	252	274	259	295	137	402	355	266	378
	Natural Gas	709	567	547	583	501	585	540	485	534	513	502	519
	Pumped Hydro	492	807	811	768	799	673	762	1,073	755	799	918	855
	Solar	62	66	72	100	73	84	82	76	68	66	60	65
	DR Credit	38	38	38	38	38	38	38	38	38	38	38	38

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Total	**1,750**	**1,773**	**1,762**	**1,787**	**1,731**	**1,684**	**1,764**	**1,854**	**1,843**	**1,816**	**1,808**	**1,878**
	CPUC Requirement	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**	**1,524**
	% of Total	**115%**	**116%**	**116%**	**117%**	**114%**	**111%**	**116%**	**122%**	**121%**	**119%**	**119%**	**123%**
	Biogas and Biomass	28	28	28	28	28	28	28	28	28	28	28	28
	Natural Gas	107	107	107	112	107	107	105	105	101	97	115	116
Humboldt	**Total**	**135**	**135**	**135**	**140**	**135**	**135**	**133**	**133**	**129**	**125**	**144**	**144**
	CPUC Requirement	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**
	% of Total	**112%**	**112%**	**112%**	**116%**	**112%**	**112%**	**110%**	**110%**	**107%**	**103%**	**119%**	**119%**
	Biogas and Biomass	3	3	3	4	4	3	3	4	4	4	4	4
	CHP	53	40	37	54	55	57	56	57	54	47	56	58
	Demand Response	0	0	0	1	1	2	2	2	2	1	1	0
	Natural Gas	274	274	274	274	274	274	274	274	274	274	274	219
Kern	Solar	23	22	22	27	21	29	38	30	30	53	43	57
	DR Credit	84	84	84	84	84	84	84	84	84	84	84	84
	Total	**437**	**423**	**420**	**444**	**439**	**449**	**457**	**451**	**448**	**463**	**462**	**422**
	CPUC Requirement	**422**	**422**	**422**	**422**	**422**	**422**	**422**	**422**	**422**	**422**	**422**	**422**
	% of Total	**104%**	**100%**	**100%**	**105%**	**104%**	**107%**	**108%**	**107%**	**106%**	**110%**	**110%**	**100%**
	Battery Storage	42	42	44	44	44	45	45	45	45	45	45	80
	Biogas and Biomass	2	2	2	2	2	2	2	2	2	2	2	2
	CHP	350	350	350	350	350	350	350	350	350	350	350	350
	Hydro	11	11	11	11	11	11	11	11	11	11	11	11
	Natural Gas	5,776	5,764	5,793	5,791	5,798	5,788	5,787	5,786	5,783	5,759	5,757	5,799
LA Basin	Solar	18	18	18	18	18	18	18	18	18	18	18	18
	Wind	90	89	101	97	97	104	98	97	92	86	89	90
	DR Credit	645	645	645	645	645	645	645	645	645	645	645	645
	LCR Credit	171	171	171	171	171	171	171	171	171	171	171	171
	Total	**7,105**	**7,092**	**7,135**	**7,129**	**7,136**	**7,134**	**7,127**	**7,125**	**7,117**	**7,087**	**7,088**	**7,166**
	CPUC Requirement	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**	**6,667**
	% of Total	**107%**	**106%**	**107%**	**107%**	**107%**	**107%**	**107%**	**107%**	**107%**	**106%**	**106%**	**107%**
NCNB	Biogas and	4	4	4	4	4	4	4	4	4	4	4	4

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Biomass												
	Geothermal	635	635	635	635	635	635	645	645	635	635	635	635
	Hydro	10	10	10	10	10	10	10	10	10	10	10	10
	DR Credit	5	5	5	5	5	5	5	5	5	5	5	5
	Total	**654**	**654**	**654**	**654**	**654**	**654**	**664**	**664**	**654**	**654**	**654**	**654**
	CPUC Requirement	**667**	**667**	**667**	**667**	**667**	**667**	**667**	**667**	**667**	**667**	**667**	**667**
	% of Total	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**	**100%**	**100%**	**98%**	**98%**	**98%**	**98%**
San Diego-IV	Battery Storage	38	38	38	39	39	39	39	39	39	39	39	39
	Biogas and Biomass	6	6	6	6	6	6	6	6	6	6	6	6
	CHP	4	4	4	4	4	4	4	4	4	4	4	4
	Natural Gas	3,317	3,317	3,317	3,317	3,314	3,208	3,156	3,156	3,156	3,317	3,317	3,317
	Pumped Hydro	40	40	40	40	40	40	40	40	40	40	40	40
	Solar	216	216	216	216	216	216	216	216	216	216	216	216
	Wind	100	100	102	102	102	102	101	101	100	100	100	100
	DR Credit	15	15	15	15	15	15	15	15	15	15	15	15
	Total	**3,736**	**3,736**	**3,738**	**3,739**	**3,736**	**3,630**	**3,577**	**3,577**	**3,576**	**3,737**	**3,737**	**3,737**
	CPUC Requirement	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**	**3,896**
	% of Total	**96%**	**96%**	**96%**	**96%**	**96%**	**93%**	**92%**	**92%**	**92%**	**96%**	**96%**	**96%**
Sierra	Biogas and Biomass	61	52	29	39	30	39	29	38	38	38	34	38
	CHP	8	8	8	8	8	8	8	8	8	0	0	0
	Hydro	1,331	1,334	1,296	1,329	1,333	1,344	1,269	1,242	1,239	1,250	1,301	1,275
	Natural Gas	163	163	165	163	145	163	179	185	175	164	163	184
	DR Credit	28	28	28	28	28	28	28	28	28	28	28	28
	Total	**1,591**	**1,586**	**1,526**	**1,567**	**1,543**	**1,582**	**1,512**	**1,501**	**1,488**	**1,480**	**1,527**	**1,525**
	CPUC Requirement	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**	**1,587**
	% of Total	**100%**	**100%**	**96%**	**99%**	**97%**	**100%**	**95%**	**95%**	**94%**	**93%**	**96%**	**96%**
Stockton	Biogas and Biomass	30	35	35	28	31	36	34	34	33	34	32	36
	CHP	44	45	45	22	38	30	39	43	44	42	46	45
	Demand Response	2	2	2	2	2	2	2	2	2	2	2	2
	Hydro	109	106	104	99	98	110	108	94	82	80	94	96

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Natural Gas	315	315	314	313	313	310	302	310	311	314	317	317
	Solar	0	0	0	0	1	0	0	0	0	0	0	0
	DR Credit	23	23	23	23	23	23	23	23	23	23	23	23
	Total	**523**	**525**	**522**	**487**	**505**	**510**	**507**	**506**	**495**	**495**	**513**	**518**
	CPUC Requirement	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**
	% of Total	**92%**	**93%**	**92%**	**86%**	**89%**	**90%**	**89%**	**89%**	**87%**	**87%**	**90%**	**91%**

As shown in Table 13, for 2021, LSEs were collectively able to meet local requirements in more local areas, though deficiencies were still present in the Kern, San Diego-IV, Sierra and Stockton local areas. Table 14 reflects the fact that no collective deficiencies were present for 2022, though LSEs were only required to meet 50% of the local requirement for Year 3.

Table 13: Resources Shown on 2021 Year Ahead Local RA Plans by Local Area (MW)

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	Battery Storage	196	196	196	193	193	493	496	496	496	493	493	571
	Biogas and Biomass	1	1	1	0	0	0	1	0	1	0	0	1
	CHP	216	216	217	177	202	218	218	217	213	213	215	217
	Natural Gas	3,394	3,390	3,406	3,488	3,463	3,125	3,141	3,141	3,102	3,138	3,179	3,085
	Solar	8	8	8	3	3	3	8	8	8	3	3	8
	Wind	123	129	111	87	88	100	77	78	119	34	48	55
	DR Credit	100	100	100	100	100	100	100	100	100	100	100	100
	RMR	148	148	148	148	148	148	148	148	148	148	148	148
	Total	**4,186**	**4,188**	**4,187**	**4,196**	**4,197**	**4,187**	**4,189**	**4,188**	**4,187**	**4,129**	**4,186**	**4,185**
	CPUC Requirement	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**	**4,053**
	% of Total	**103%**	**103%**	**103%**	**104%**	**104%**	**103%**	**103%**	**103%**	**103%**	**102%**	**103%**	**103%**
Big Creek-Ventura	Battery Storage	175	175	206	206	206	206	206	206	206	206	206	206
	Biogas and Biomass	26	23	26	25	22	29	26	26	25	25	25	24
	CHP	79	79	79	79	79	79	41	41	41	41	41	41
	Hydro	735	735	735	735	735	735	735	735	735	735	735	735

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Natural Gas	989	989	995	999	1,003	1,005	1,003	1,003	1,003	999	989	989
	Pumped Hydro	199	199	199	199	199	199	199	199	199	199	199	199
	Solar	166	166	166	166	166	163	157	166	166	166	166	166
	DR Credit	133	133	133	133	133	133	133	133	133	133	133	133
	Total	**2,502**	**2,499**	**2,539**	**2,542**	**2,543**	**2,549**	**2,500**	**2,509**	**2,508**	**2,504**	**2,494**	**2,493**
	CPUC Requirement	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**	**2,332**
	% of Total	**107%**	**107%**	**109%**	**109%**	**109%**	**109%**	**107%**	**108%**	**108%**	**107%**	**107%**	**107%**
Fresno	Biogas and Biomass	26	26	26	26	26	26	19	19	19	19	26	26
	CHP	2	2	2	2	2	2	3	3	3	3	2	3
	Hydro	483	91	91	122	174	143	204	91	302	314	174	350
	Natural Gas	674	579	536	589	525	578	486	396	444	402	407	408
	Pumped Hydro	362	850	894	769	765	780	783	1,026	767	763	943	761
	Solar	65	63	81	111	136	111	147	97	85	68	62	65
	Solar Hybrid	0	0	0	0	0	41	104	86	66	48	48	45
	DR Credit	38	38	38	38	38	38	38	38	38	38	38	38
	Total	**1,650**	**1,649**	**1,669**	**1,658**	**1,667**	**1,720**	**1,783**	**1,756**	**1,724**	**1,655**	**1,701**	**1,696**
	CPUC Requirement	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**	**1,527**
	% of Total	**108%**	**108%**	**109%**	**109%**	**109%**	**113%**	**117%**	**115%**	**113%**	**108%**	**111%**	**111%**
Humboldt	Biogas and Biomass	15	15	15	15	15	15	15	15	15	15	15	15
	Natural Gas	113	118	118	117	119	119	119	119	119	110	119	119
	Total	**128**	**133**	**133**	**133**	**134**	**134**	**134**	**134**	**134**	**125**	**134**	**134**
	CPUC Requirement	**122**	**122**	**122**	**122**	**122**	**122**	**122**	**122**	**122**	**122**	**122**	**122**
	% of Total	**105%**	**109%**	**109%**	**109%**	**110%**	**110%**	**110%**	**110%**	**110%**	**103%**	**110%**	**110%**
Kern	Biogas and Biomass	4	4	4	4	4	4	4	4	4	4	4	4
	CHP	57	57	57	57	57	57	57	57	57	57	57	57
	Demand Response	1	1	1	1	2	3	3	3	3	2	1	1
	Natural Gas	214	214	214	214	214	215	215	215	215	214	214	214
	Solar	57	57	57	57	57	59	59	55	57	57	57	62
	DR Credit	84	84	84	84	84	84	84	84	84	84	84	84
	Total	**417**	**417**	**417**	**417**	**418**	**422**	**422**	**418**	**420**	**418**	**417**	**422**

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	CPUC Requirement	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**	**421**
	% of Total	**99%**	**99%**	**99%**	**99%**	**99%**	**100%**	**100%**	**99%**	**100%**	**99%**	**99%**	**100%**
LA Basin	Battery Storage	200	200	200	200	200	200	200	200	200	200	200	200
	Biogas and Biomass	7	7	7	7	7	7	7	7	7	7	7	7
	CHP	350	350	350	350	350	321	321	321	321	321	321	321
	Demand Response	15	15	15	15	15	15	15	15	15	15	15	15
	Hydro	11	11	11	11	11	11	11	11	11	11	11	11
	Natural Gas	5,079	5,079	5,079	5,069	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079
	Solar	20	20	20	20	20	20	20	20	20	20	20	20
	Wind	68	68	72	72	72	74	71	70	68	52	54	54
	DR Credit	628	628	628	628	628	628	628	628	628	628	628	628
	LCR Credit	196	196	196	196	196	196	196	196	196	196	196	196
	Total	**6,574**	**6,574**	**6,578**	**6,568**	**6,578**	**6,551**	**6,548**	**6,547**	**6,545**	**6,529**	**6,531**	**6,531**
	CPUC Requirement	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**	**6,474**
	% of Total	**102%**	**102%**	**102%**	**101%**	**102%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**
NCNB	Biogas and Biomass	4	4	4	4	4	4	4	4	4	4	4	4
	Geothermal	593	593	593	593	593	593	593	593	593	593	593	593
	Hydro	10	10	10	10	10	10	10	10	10	10	10	10
	DR Credit	5	5	5	5	5	5	5	5	5	5	5	5
	Total	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**612**
	CPUC Requirement	**608**	**608**	**608**	**608**	**608**	**608**	**608**	**608**	**608**	**608**	**608**	**608**
	% of Total	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**	**101%**
San Diego-IV	Battery Storage	69	69	69	69	69	109	109	109	115	115	115	115
	Biogas and Biomass	6	6	6	6	6	6	6	6	6	6	6	6
	CHP	4	4	4	4	4	4	4	4	4	4	4	4
	Natural Gas	3,309	3,309	3,309	3,309	3,308	3,306	3,305	3,306	3,307	3,309	3,309	3,309
	Pumped Hydro	40	40	40	40	40	40	40	40	40	40	40	40
	Solar	225	227	234	234	234	235	233	233	233	223	223	216
	Wind	117	114	109	109	109	109	109	109	109	117	127	129
	DR Credit	16	16	16	16	16	16	16	16	16	16	16	16

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Total	**3,786**	**3,785**	**3,787**	**3,787**	**3,786**	**3,825**	**3,822**	**3,823**	**3,830**	**3,830**	**3,840**	**3,835**
	CPUC Requirement	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**	**4,037**
	% of Total	**94%**	**94%**	**94%**	**94%**	**94%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**
Sierra	Biogas and Biomass	29	34	36	36	30	39	38	38	33	38	34	38
	Hydro	1,284	1,278	1,288	1,366	1,334	1,348	1,353	1,353	1,341	1,215	1,276	1,205
	Natural Gas	145	145	145	95	142	142	142	142	142	142	142	142
	DR Credit	28	28	28	28	28	28	28	28	28	28	28	28
	Total	**1,487**	**1,486**	**1,498**	**1,525**	**1,535**	**1,558**	**1,562**	**1,562**	**1,545**	**1,424**	**1,480**	**1,413**
	CPUC Requirement	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**	**1,589**
	% of Total	**94%**	**94%**	**94%**	**96%**	**97%**	**98%**	**98%**	**98%**	**97%**	**90%**	**93%**	**89%**
Stockton	Biogas and Biomass	35	35	35	30	31	36	33	33	33	34	33	36
	CHP	44	47	46	29	35	42	41	46	49	40	48	49
	Demand Response	2	2	2	2	2	2	2	2	2	2	2	2
	Hydro	98	98	97	100	102	101	102	100	96	85	94	96
	Natural Gas	315	315	314	313	312	310	309	310	311	313	315	314
	Solar	0	0	0	0	1	1	0	0	0	0	0	0
	DR Credit	23	23	23	23	23	23	23	23	23	23	23	23
	Total	**517**	**519**	**517**	**497**	**505**	**514**	**509**	**513**	**514**	**497**	**514**	**519**
	CPUC Requirement	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**
	% of Total	**91%**	**91%**	**91%**	**88%**	**89%**	**91%**	**90%**	**90%**	**91%**	**88%**	**91%**	**92%**

Table 14: Resources Shown on 2022 Year Ahead Local RA Plans by Local Area (MW)

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	Battery Storage	571	568	568	568	568	568	568	568	568	568	568	568
	CHP	217	217	217	217	217	217	217	217	217	217	217	217
	Natural Gas	1,646	1,655	1,651	1,651	1,651	1,650	1,664	1,663	1,650	1,650	1,653	1,654
	Solar	3	3	3	3	3	3	3	3	3	3	3	3
	Wind	66	62	91	75	75	86	72	69	60	49	56	57
	DR Credit	49	49	49	49	49	49	49	49	49	49	49	49

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	RMR	74	74	74	74	74	74	74	74	74	74	74	74
	Total	**2,627**	**2,629**	**2,654**	**2,638**	**2,638**	**2,648**	**2,648**	**2,644**	**2,622**	**2,611**	**2,621**	**2,623**
	CPUC Requirement	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**	**2,012**
	% of Total	**131%**	**131%**	**132%**	**131%**	**131%**	**132%**	**132%**	**131%**	**130%**	**130%**	**130%**	**130%**
Big Creek-Ventura	Battery Storage	192	192	192	192	192	192	192	192	192	192	192	192
	Biogas and Biomass	15	12	15	13	10	17	14	15	13	13	13	12
	CHP	66	66	66	66	66	66	66	66	66	66	66	66
	Hydro	294	294	294	294	294	294	294	294	294	294	294	294
	Natural Gas	609	609	614	617	620	622	620	620	620	617	609	609
	Solar	166	166	166	166	166	163	157	166	166	166	166	166
	DR Credit	64	64	64	64	64	64	64	64	64	64	64	64
	Total	**1,406**	**1,403**	**1,411**	**1,412**	**1,412**	**1,418**	**1,407**	**1,417**	**1,415**	**1,412**	**1,404**	**1,403**
	CPUC Requirement	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**
	% of Total	**120%**	**120%**	**121%**	**121%**	**121%**	**121%**	**120%**	**121%**	**121%**	**121%**	**120%**	**120%**
Fresno	Biogas and Biomass	19	19	19	19	19	19	19	19	19	19	19	19
	CHP	2	2	2	2	2	2	3	3	3	3	2	3
	Hydro	178	91	91	119	143	143	143	91	225	174	171	143
	Natural Gas	411	452	409	448	356	443	396	351	399	357	362	363
	Pumped Hydro	305	352	392	291	387	297	363	465	287	354	338	359
	Solar	65	63	81	111	85	103	114	97	79	62	62	65
	Solar Hybrid	51	50	72	68	69	92	104	86	66	48	48	45
	DR Credit	19	19	19	19	19	19	19	19	19	19	19	19
	Total	**1,050**	**1,047**	**1,085**	**1,077**	**1,080**	**1,117**	**1,160**	**1,130**	**1,098**	**1,036**	**1,021**	**1,016**
	CPUC Requirement	**768**	**768**	**768**	**768**	**768**	**768**	**768**	**768**	**768**	**768**	**768**	**768**
	% of Total	**137%**	**136%**	**141%**	**140%**	**141%**	**146%**	**151%**	**147%**	**143%**	**135%**	**133%**	**132%**
Humboldt	Biogas and Biomass	15	15	15	15	15	15	15	15	15	15	15	15
	Natural Gas	71	71	71	71	73	73	75	75	75	71	69	69
	DR Credit	0	0	0	0	0	0	0	0	0	0	0	0
	Total	**86**	**86**	**86**	**86**	**88**	**88**	**90**	**90**	**90**	**86**	**84**	**84**
	CPUC Requirement	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	% of Total	**135%**	**135%**	**135%**	**135%**	**138%**	**138%**	**141%**	**141%**	**141%**	**135%**	**132%**	**132%**
Kern	Biogas and Biomass	0	0	0	0	4	4	4	4	4	4	4	4
	CHP	18	18	18	0	39	39	39	39	39	39	39	39
	Natural Gas	168	168	168	168	66	67	67	67	67	66	66	65
	Solar	2	2	2	2	59	59	59	59	59	59	59	59
	Solar Hybrid	45	44	63	59	60	80	90	75	58	43	43	40
	DR Credit	42	42	42	42	42	42	42	42	42	42	42	42
	Total	**275**	**274**	**293**	**271**	**270**	**291**	**301**	**286**	**269**	**253**	**253**	**249**
	CPUC Requirement	**215**	**215**	**215**	**215**	**215**	**215**	**215**	**215**	**215**	**215**	**215**	**215**
	% of Total	**128%**	**128%**	**136%**	**126%**	**126%**	**135%**	**140%**	**133%**	**125%**	**118%**	**118%**	**116%**
LA Basin	Battery Storage	100	100	100	100	100	100	100	100	100	100	100	100
	CHP	304	304	304	304	304	304	44	44	44	44	44	44
	Hydro	11	11	11	11	11	11	11	11	11	11	11	11
	Natural Gas	2,402	2,402	2,402	2,402	2,402	2,402	2,680	2,680	2,680	2,680	2,680	2,680
	Solar	17	17	17	17	17	17	17	17	17	17	17	17
	Wind	29	28	33	32	32	35	32	31	29	23	24	24
	DR Credit	303	303	303	303	303	303	303	303	303	303	303	303
	LCR Credit	95	95	95	95	95	95	95	95	95	95	95	95
	Total	**3,262**	**3,261**	**3,266**	**3,265**	**3,265**	**3,268**	**3,283**	**3,282**	**3,280**	**3,274**	**3,275**	**3,275**
	CPUC Requirement	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**	**2,825**
	% of Total	**115%**	**115%**	**116%**	**116%**	**116%**	**116%**	**116%**	**116%**	**116%**	**116%**	**116%**	**116%**
NCNB	Biogas and Biomass	4	4	4	4	4	4	4	4	4	4	4	4
	Geothermal	372	372	372	372	372	372	372	372	372	372	372	372
	Hydro	9	9	9	9	9	9	9	9	9	9	9	9
	DR Credit	3	3	3	3	3	3	3	3	3	3	3	3
	Total	**387**	**387**	**387**	**387**	**387**	**387**	**387**	**387**	**387**	**387**	**387**	**387**
	CPUC Requirement	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**
	% of Total	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**	**125%**
San Diego-IV	Battery Storage	132	132	132	132	132	132	132	132	132	132	132	132
	Biogas and Biomass	6	6	6	6	6	6	6	6	6	6	6	6

Local Area	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	CHP	4	4	4	4	4	4	4	4	4	4	4	4
	Natural Gas	2,774	2,774	2,774	2,774	2,774	2,774	2,774	2,774	2,774	2,774	2,774	2,774
	Pumped Hydro	40	40	40	40	40	40	40	40	40	40	40	40
	Solar	216	216	216	216	216	216	216	216	216	216	216	216
	Wind	113	111	128	125	125	133	123	121	114	107	111	112
	DR Credit	9	9	9	9	9	9	9	9	9	9	9	9
	Total	**3,294**	**3,292**	**3,309**	**3,306**	**3,306**	**3,314**	**3,304**	**3,302**	**3,295**	**3,288**	**3,292**	**3,293**
	CPUC Requirement	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**	**1,966**
	% of Total	**168%**	**167%**	**168%**	**168%**	**168%**	**169%**	**168%**	**168%**	**168%**	**167%**	**167%**	**168%**
Sierra	Biogas and Biomass	39	24	29	39	30	29	29	38	24	28	24	28
	Hydro	765	776	774	762	757	767	753	709	717	600	733	734
	Natural Gas	142	142	142	142	142	142	142	142	142	142	142	142
	DR Credit	13	13	13	13	13	13	13	13	13	13	13	13
	Total	**959**	**956**	**958**	**957**	**942**	**952**	**937**	**902**	**896**	**783**	**912**	**918**
	CPUC Requirement	**794**	**794**	**794**	**794**	**794**	**794**	**794**	**794**	**794**	**794**	**794**	**794**
	% of Total	**121%**	**120%**	**121%**	**120%**	**119%**	**120%**	**118%**	**114%**	**113%**	**99%**	**115%**	**116%**
Stockton	Biogas and Biomass	30	30	29	13	13	13	13	13	13	13	15	15
	CHP	39	41	41	35	34	31	40	43	45	41	49	49
	Demand Response	2	2	2	2	2	2	2	2	2	2	2	2
	Hydro	18	18	17	7	8	7	93	2	2	2	93	95
	Natural Gas	220	217	217	237	242	253	157	249	247	238	115	115
	DR Credit	11	11	11	11	11	11	11	11	11	11	11	11
	Total	**319**	**317**	**317**	**304**	**309**	**316**	**316**	**320**	**320**	**307**	**285**	**286**
	CPUC Requirement	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**
	% of Total	**112%**	**111%**	**111%**	**107%**	**108%**	**111%**	**111%**	**112%**	**112%**	**107%**	**100%**	**100%**

4. DEVELOPMENT OF PREFERRED RESOURCES IN LOCAL AND SYSTEM AREAS

Resources must be on the Net Qualifying Capacity (NQC) List in order to be counted for RA. Table 15 identifies the new preferred resources that were added to the NQC list from August to December 2019. Only nine new preferred resources with a combined net dependable capacity of 136.1 MW were added during this period, however most are currently "energy only" resources so have NQC values of 0. Total August NQC added was 32.4 MW. All of these resources are contracted with IOUs.

Table 15: New Preferred Resources on NQC List August-December 2019.

Local Area	LSE Type	Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
Big Creek-Ventura	IOU	BGSKYN_2_BS3SR3	Big Sky Solar 3	Solar PV	5.4	20
		DELSUR_6_SOLAR4	Radiance Solar 4	Solar PV	0	1.5
		DELSUR_6_SOLAR5	Radiance Solar 5	Solar PV	0	1.5
		SAUGUS_6_CREST	East Portal Hydro	Hydro	0	1.0
Fresno	IOU	GIFFEN_6_SOLAR1	Aspiration Solar G	Solar PV	0	9.0
		STROUD_6_WWHSR1	Winter Wheat Solar Farm	Solar PV	0	1.5
		SCHNDR_1_OS2BM2	Open Sky Digester Genset 2	Biogas	0	0.8
		DAIRLD_1_MD2BM1	Madera Digester Genset 2	Biogas	0	0.8
CAISO System	IOU	VALTNE_2_AVASR1	Valentine Solar	Solar PV	27	100

5. LOCAL, SYSTEM AND FLEXIBLE RA DEFICIENCIES

On October 31, 2018, 10 of the 36 Commission-jurisdictional LSEs, submitted local waiver requests due to their inability to procure sufficient capacity in one or more local areas to meet their 2019 year ahead local RA requirements. These LSEs included:

- one IOU (San Diego Gas & Electric Company (SDG&E));
- six CCAs (East Bay Community Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, San Jose Clean Energy, Sonoma Clean Power Authority, and Valley Clean Energy Authority); and
- three ESPs (Constellation NewEnergy, Inc., Direct Energy Business, and Just Energy Solutions, Inc. Additionally, a fourth ESP, Commercial Energy of Montana, was found to have a local deficiency but did not file a waiver).

This was not the first year that numerous LSEs have experienced difficulty procuring local capacity – but the underlying facts differed significantly from 2019. In the 2018 year ahead filings, most individual local deficiencies were concentrated in the San Diego-IV local area and were a result of LSEs' inability to contract with Encina Generating Station due to the resource' stated intent to retire at the end of 2017 in compliance with State Water Board once-through-cooling requirements. For 2019, local deficiencies were much more dispersed with deficiencies in the Other PG&E, Bay Area, LA Basin, and San Diego-IV local areas.

LSEs cited several reasons for these deficiencies in their local waiver requests. All of the LSEs issued Requests for Offers (RFOs) and/or bid into RFOs issued by other entities. While some were able to procure capacity, none of the LSEs seeking local waivers received enough to meet local RA requirements at prices they deemed reasonable. While some LSEs rejected offers they considered too high, many were unable to procure capacity even when they offered prices well above the local trigger price of $40/kw-year. LSEs also reached out directly to generators, brokers, and other LSEs, but were unable to identify sufficient available capacity to meet their requirements.

Specific 2019 local deficiencies are detailed in Table 16. Despite these deficiencies, CAISO determined that there were no aggregate deficiencies in the SCE and SDG&E

TAC areas. The Humbolt, Sierra, North Coast/North Bay, Stockton, and Fresno local areas were still aggregated into the Other Pacific Gas & Electric (PG&E) area for 2019 RA compliance purposes. Despite collective deficiencies in several of these local areas, CAISO performed no backstop procurement.[5]

Table 16: 2019 Year Ahead Local Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	MW	1.92	69.87	3.85	1.92	4.87	1.92	1.92	1.92	22.87	8.87	0	1.92
	# of LSEs	1	2	2	1	2	1	1	1	2	2	0	1
Other PG&E	MW	27.77	169.09	7.09	10.69	130.77	44.81	192.96	30.96	338.65	205.73	108.25	145.45
	# of LSEs	5	4	3	2	6	5	7	4	9	7	7	8
LA Basin	MW	1.24	1.24	1.24	1.24	1.24	2.12	2.12	2.12	2.12	2.12	2.12	2.12
	# of LSEs	1	1	1	1	1	2	2	2	2	2	2	2
San Diego-IV	MW	0	0	0	17.29	0	255.24	255.02	255.24	255.57	97.79	0	0
	# of LSEs	0	0	0	1	0	1	1	1	1	1	0	0

The year ahead local deficiencies generally persisted in month ahead filings, though some LSEs were able to cure their deficiencies in certain months. Additionally, a small deficiency occurred in Big Creek/Ventura for July that had not previously been present. Table 17 shows local deficiencies on month ahead showings from January through December 2019.

[5] See http://www.caiso.com/Documents/EvaluationReport_LoadServingEntitiesCompliance_2019Local_SystemResourceAdequacyRequirements.pdf.

Table 17: 2019 Month Ahead Local Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	**MW**	1.92	62.95	0	1.92	0	0	1.92	1.92	3.87	0	0	1.92
	# of LSEs	1	1	0	1	0	0	1	1	2	0	0	1
Other PG&E	**MW**	19.56	163.77	0.89	0.89	89.65	32.09	126.65	3.77	282.43	163.98	46.06	104.88
	# of LSEs	3	3	1	1	4	3	4	2	6	4	3	4
LA Basin	**MW**	1.24	1.24	1.24	0	0	2.12	1.24	1.24	2.12	1.24	1.24	1.24
	# of LSEs	1	1	1	0	0	2	1	1	2	1	1	1
Big Creek/ Ventura	**MW**	0	0	0	0	0	0	0.81	0	0	0	0	0.81
	# of LSEs	0	0	0	0	0	0	1	0	0	0	0	1
San Diego/IV	**MW**	0	0	0	0	0	0	239.02	239.24	249.58	63.79	0	0
	# of LSEs	0	0	0	0	0	0	1	1	1	1	0	0

Table 18 shows system RA deficiencies in the year ahead (YA) and month ahead (MA) filings for 2019. Year ahead filings cover only the five summer months (May through September) so there were no deficiencies for off-peak months the year ahead timeframe. Even in the month ahead timeframe, deficiencies were minimal in those months. Larger deficiencies have been seen on the system level for the peak summer months, particularly July and September. While deficiencies were cured to some extent between the year ahead and month ahead filings, collective deficiencies of 159.15 MW for July and 847.02 MW for August remained for CPUC jurisdictional LSEs. A similar trend was seen for flexible deficiencies with a 114.1 MW deficiency remaining for September in the month ahead filings (Table 19).

Table 18: 2019 Year Ahead and Month Ahead System Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
YA	MW	NA	NA	NA	NA	5.49	23.25	528.12	35.80	979.21	NA	NA	NA
	# of LSEs					1	3	5	4	6			
MA	MW	1.8	2.45	0	0.6	6.86	20.8	159.15	27.8	847.02	0	2.62	5.61
	# of LSEs	1	1	0	1	2	2	4	3	5	0	1	2

Table 19: 2019 Year Ahead and Month Ahead Flexible Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
YA	MW	8	9	2	2	2	5	36.1	3	130.1	86.1	4	7
	# of LSEs	2	2	1	1	1	3	2	1	5	4	1	2
MA	MW	3	0	2	2	0	2	1	3	114.1	1	1	6
	# of LSEs	2	0	1	1	0	1	1	1	4	1	1	2

On October 31, 2019, 20 of the 42 Commission-jurisdictional LSEs, submitted local waiver requests due to their inability to procure sufficient capacity to meet their 2020-2022 year ahead local RA requirements in one or more local areas. These LSEs include:

- two IOUs (Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E));
- nine CCAs (CleanPowerSF, East Bay Community Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, San Jose Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority; and
- nine ESPs (Commercial Energy, Constellation NewEnergy, Inc., Direct Energy Business, EDF Industrial Power Services, Just Energy Solutions, Inc., Pilot Power Group, Shell Energy North America, Three Phases Renewables, University of California).

LSEs cited similar procurement challenges in their 2020-2022 waiver requests as in the 2019 requests, – especially tightness in the market and inability to find available capacity. The introduction of a multiyear requirement as well as disaggregation of the PG&E Other local areas appear to have been factors in the increased number of waiver requests for 2020-2022. As noted by PG&E in its Advice Letter submission, the total level of generating capacity available in the Kern, Sierra, and Stockton local areas is very close to the 2020 local requirement for those areas. Additionally, the local requirements were generated using the 2019 NQC list, so they do not reflect reduced solar and wind effective load carrying capability (ELCC) values adopted for 2020.

Table 20, Table 21, and Table 22 outline year ahead 2020-2022 local deficiencies. 2020 system and flexible deficiencies are described in Table 23. Note that these are preliminary determinations as the year ahead compliance process has not yet been completed for 2020. LSEs will be given the opportunity to cure any deficiencies during this process.

Table 20: 2020 Year Ahead Local Deficiencies (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	0	0	0	0	0	12.22	13.18	13.18	0.99	0.03	0	0
Fresno	12.81	12.62	64.59	64.82	64.82	83.58	47.79	0.97	45.79	45.79	0	0
Humboldt	6.98	6.98	6.98	6.98	6.98	6.98	9.97	9.97	16.95	16.95	0	0
Kern	18.97	29.16	28.57	6.27	6.69	4.17	1.86	1.33	3.60	1.33	1.33	8.54
LA Basin	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
NCNB	30.4	30.4	30.4	30.4	30.4	30.4	20.4	20.4	30.4	30.4	30.4	30.4
San Diego-IV	183.21	183.44	181.64	180.98	183.85	288.82	341.94	342.17	342.84	182.88	182.44	182.32
Sierra	77.04	76.89	80.39	78.2	78.38	78.38	120.59	114.89	132.8	145.23	78.13	77.92
Stockton	53.04	53.33	53.87	86.12	72.19	66.41	68.21	69.26	80.02	86.53	61.74	55.36
# of LSEs	**10**	**11**	**11**	**12**	**10**	**11**	**14**	**15**	**15**	**12**	**12**	**12**

Table 21: 2021 Year Ahead Local Deficiencies (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	49.18	6.26	6.26
Big Creek-Ventura	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Fresno	18.99	18.99	18.99	18.99	18.99	18.99	18.99	18.99	18.99	19.96	18.99	18.99
Kern	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40
LA Basin	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45	15.45
NCNB	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
San Diego-IV	293.73	293.96	292.16	292.5	289.57	242.69	242.3	244.04	240.48	247.38	235.14	240.21
Sierra	120.73	124.64	120.09	114.76	113.00	94.14	99.34	99.34	117.78	220.16	140.35	196.12
Stockton	57.14	57.54	58.29	75.66	68.92	72.09	77.68	74.17	71.89	77.35	57.62	52.61
# of LSEs	**18**	**18**	**18**	**18**	**19**	**16**	**18**	**17**	**17**	**18**	**19**	**20**

Table 22: 2022 Year Ahead Local Deficiencies (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bay Area	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
Fresno	0	0.575	0	0	0	0	0	0	0	0	1.25	2.6
Humboldt	1.99	1.99	1.99	1.99	1.99	1.99	0	0	0	0	1.99	1.99
NCNB	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74
Sierra	42.3	46.72	41.77	42.05	55.45	46.92	66.17	94.85	95.51	120.61	94.08	89.7
Stockton	8.34	8.34	8.34	19.14	8.34	8.34	3.38	3.38	3.38	3.38	45.36	45.36
# of LSEs	**5**	**5**	**5**	**6**	**5**	**5**	**6**	**7**	**8**	**10**	**9**	**9**

Table 23: 2020 Year Ahead System and Flexible Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System	MW	NA	NA	NA	NA	0	11.44	16.17	17.34	266.67	NA	NA	NA
	# of LSEs					0	1	2	2	5			
Flexible	MW	2	2	2	1	1	4	5	6	6	5	4	1
	# of LSEs	1	1	1	1	1	1	2	2	2	1	2	1

6. RESOURCES NOT SHOWN IN YEAR AHEAD RA FILINGS

Table 24 depicts the amount of capacity internal to California that was not shown in 2020 year ahead RA filings. To calculate these values, the amount of resources under construction shown by LSEs in their year ahead filings was added to the amount of capacity listed on the 2020 NQC list. Resources shown by CPUC jurisdictional LSEs on year ahead RA plans, non-jurisdictional LSEs on year ahead supply plans and RMR resources were then subtracted from the total. (Demand response resources are not included since most are not listed on RA plans.) LSEs must meet 90% of their system requirements in the year-ahead process for the five summer months; thus, many of these resources would be expected to be shown in the month-ahead system RA process.

Table 24: In State Resources not Shown on 2020 Year Ahead (90%) RA Filings (MW)

	May	Jun	Jul	Aug	Sep
Battery Storage	4				
Biogas & Biomass	222	176	173	173	181
CDWR Pumps	439	418	418	418	418
CHP	308	295	243	242	230
Geothermal	249	234	222	232	232
Hydro	2,342	1,895	2,396	2,195	1,760
Natural Gas	2,670	2,244	2,243	2,484	2,482
Nuclear	1,306	1,477	827	825	1,219
Pumped Hydro	575	110	85	74	42
Solar	488	254	277	310	173
Wind	455	377	262	271	182
Total	**9,057**	**7,480**	**7,146**	**7,224**	**6,918**

In addition to the internal resources listed above, Table 25 shows the unused maximum import capability (MIC) for the peak months of 2020 after imports of both CPUC jurisdictional and non-jurisdictional LSEs year ahead showings of import RA are accounted for. For September, which is forecast to be the peak load month of 2020, 4,368 MW of MIC were unused.

Table 25: Remaining Import Capability (MW)

	May	Jun	Jul	Aug	Sep
Total MIC	10,193	10,193	10,193	10,193	10,193
CPUC Imports on RA Plans	2,666	3,235	3,389	3,804	4,328
Non-CPUC Imports on Supply Plans	1,244	1,364	1,516	1,574	1,497
Remaining MIC	**6,283**	**5,594**	**5,288**	**4,815**	**4,368**

Table 26 compares the remaining internal capacity listed on the NQC list and unused MIC with the capacity needed for CPUC-jurisdictional LSEs to meet system RA requirement. While LSEs have already shown sufficient resources to meet requirements for May and June, additional resources must be shown to reach 100% of the requirement in July, August, and September. The system appears particularly tight in September where an additional 6,189 MW of capacity is needed out of a remaining 11,286 MW of remaining internal resources and MIC.

Table 26: Remaining System Resources

	May	Jun	Jul	Aug	Sep
Total Requirement (100%)	36,968	42,282	46,668	47,085	47,114
YA CPUC Internal Resources Shown	34,855	39,248	40,117	38,433	36,597
YA CPUC Imports Shown	2,666	3,235	3,389	3,804	4,328
Remaining Requirement	**(553)**	**(201)**	**3,162**	**4,848**	**6,189**
Internal Resources Not Shown	9,057	7,480	7,146	7,224	6,918
Remaining MIC	6,283	5,594	5,288	4,815	4,368
Total Remaining	**15,341**	**13,075**	**12,434**	**12,039**	**11,286**

7. CONCLUSION

Overall, the data provided in this report suggest that the RA market remains tight.

In 2019, 11 LSEs had year ahead local deficiencies, six had year ahead system deficiencies, and five had year ahead flexible deficiencies, and many of these deficiencies persisted through the year in month ahead filings. In addition, some LSEs reported being unable to identify available capacity at any price. September, which was the forecasted peak load month of 2019, proved to be the most challenging. Five LSEs had September 2019 deficiencies totaling 847.02 MW which resulted in a cumulative deficiency for CPUC jurisdictional LSEs for the first time.

This trend continued in the 2020 year ahead filings, in which, preliminarily, 20 LSEs had year ahead local deficiencies, five had year ahead system deficiencies, and four had year ahead flexible deficiencies. These totals may change once LSEs have had the opportunity to cure deficiencies.

Despite this increasing number of deficiencies, there does appear to be unused capacity in the system. An estimated 6,368 MW of unused capacity was listed on the NQC list for September 2019. While not all of this capacity was available (due to retirements, water limitations, etc.), it is highly likely that significantly more than 850 MW was physically available. Additionally, while a higher than normal amount of imports was shown for RA in September, 2,685 MW of MIC went unused.

Similarly, although there were system deficiencies in the 2020 year ahead filings, in aggregate LSEs were able to meet CPUC year ahead system RA 90% requirements as a result of some LSEs showing more MW than required. Additionally, for September 2020, there were 6,918 MW of capacity on the NQC list that was not shown and 4,368 MW of remaining MIC, although most of that capacity is needed to meet 100% month ahead RA requirements.

On a local level, however, it may not be possible for LSEs to meet requirements in all local areas due to a mismatch been 2020 local requirements and NQC values for solar and wind resources due to adoption of revised ELCC values and disaggregation of the PG&E Other local area. In addition, non-CPUC jurisdictional LSEs may have capacity in these local areas that they are unwilling to sell because they do not have disaggregated local requirements.

One trend of note has been the increased use of imports to meet RA requirements, particularly among CCAs. Nearly 6,000 MW of import RA was shown on September 2019 RA plans, a significant increase over previous years. This was 13% of total capacity shown including 12% of IOU capacity, 15% of CCA capacity, and 13% of ESP capacity. In year ahead showings for September 2020, 17% of MW shown by CCAs were imports, compared with 8% for both IOUs and ESPs and 10% of total resources shown.

Although it appears that there is currently sufficient capacity on the system, and compliance with RA requirements is possible, we can expect that the market will continue to tighten. Few new resources came online in 2019 though more are expected in 2020 and beyond. As we move forward, it will be important to ensure that adequate resources are available to maintain local and system reliability and a robust RA market.

Attachment D – PG&E Workpapers

09.ERRA_2021Forecast_WP_PGE_20200701_Ch09_CONF.xlsx

Tab: CONF CAL Table 9-1

Attachment is confidential.

13.ERRA 2021 Forecast_WP_PGE_20200701_Ch13_CONF.xlsx

Tab: RA Adder

Attachment is confidential.

14.ERRA 2021-Forecast_WP_PGE_202007001_Ch14_PUBLIC

Tab: One Time Adjustments

Pacific Gas & Electric Company
Energy Resource Balancing Account (ERRA)
One Time Adjustment - Transfer ERRA balance (except Revenue Deferral) to PABA

		Jan-April 2020 Recorded	May-Dec 2020 Forecast	Jan-Dec 2020 Forecast
			RF&U=	**0.011221**
Line No.		**Jan-April 2020 Recorded**	**May-Dec 2020 Forecast**	**Jan-Dec 2020 Forecast**
1	Recorded 2019 ERRA balance	$ (616,011,174.15)		$ (616,011,174.15)
2	D.20-02-047 related transfer to PABA, recorded in 2020			$ -
3	Unsold RPS adjustment	$ 69,261,720.00		$ 69,261,720.00
4	CAM Misallocation	$ 141,267,276.15		$ 141,267,276.15
5	Adjusted 2019 ERRA balance	$ (405,482,178.00)		$ (405,482,178.00)
6	January through December 2020 Transactions			
7	ERRA Cost	$ 588,760,821.78	$ 1,550,898,133.36	$ 2,139,658,955.13
8	ERRA Revenue less RF&U	$ (693,266,133.86)	$ (1,790,157,670.85)	$ (2,483,423,804.71)
9	Revenue Deferral included in ERRA Rates (line 6)			
10	Billed Revenue Deferral		$286,428,780	$ 286,428,780.27
11	Less: RF&U of Billed Revenue Deferral		$ (3,214,017.34)	$ (3,214,017.34)
12	Balancing Account Interest	$ (3,220,111.83)	$ (8,179,722.28) *Dec 2020 fcst interest excluded*	$ (11,399,834.11)
9	**Total**	**$ (513,207,601.91)**	**$ 35,775,503.15**	**$ (477,432,098.76)**
	Debit ERRA			**$ (1,029,510,809.16)**
	Credit PABA (Vin2020)			**$ 1,029,510,809.16**